OTTR 10-K 12/31/2007

Section 1: 10-K (ANNUAL REPORT)

Table of Contents

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☑ **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2007

☐ **Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from _________ to _________

Commission File Number 0-368

OTTER TAIL CORPORATION
(Exact name of registrant as specified in its charter)

MINNESOTA (State or other jurisdiction of incorporation or organization)	**41-0462685** (I.R.S. Employer Identification No.)
215 SOUTH CASCADE STREET, BOX 496, FERGUS FALLS, MINNESOTA (Address of principal executive offices)	**56538-0496** (Zip Code)

Registrant's telephone number, including area code: **866-410-8780**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
COMMON SHARES, par value $5.00 per share	**The NASDAQ Stock Market LLC**

Securities registered pursuant to Section 12(g) of the Act:

CUMULATIVE PREFERRED SHARES, without par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. (Yes ☑ No ☐)

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. (Yes ☐ No ☑)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. (Yes ☑ No ☐)

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑	Accelerated Filer ☐	Non-Accelerated Filer ☐ (Do not check if a smaller reporting company)	Smaller Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). (Yes ☐ No ☑)

The aggregate market value of the voting stock held by non-affiliates, computed by reference to the last sales price, on June 29, 2007 was **$945,987,487.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **29,892,988 Common Shares ($5 par value) as of February 15, 2008.**

Documents Incorporated by Reference:

2007 Annual Report to Shareholders-Portions incorporated by reference into Parts I and II
Proxy Statement for the 2008 Annual Meeting-Portions incorporated by reference into Part III

TABLE OF CONTENTS

PART I

Item 1. BUSINESS

(a) General Development of Business

Otter Tail Corporation (the Company) was incorporated in 1907 under the laws of the State of Minnesota. The Company's executive offices are located at 215 South Cascade Street, P.O. Box 496, Fergus Falls, Minnesota 56538-0496 and 4334 18th Avenue SW, Suite 200, P.O. Box 9156, Fargo, North Dakota 58106-9156. Its telephone number is (866) 410-8780.

The Company makes available free of charge at its internet website (www.ottertail.com) its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, Forms 3, 4 and 5 filed on behalf of directors and executive officers and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. Information on the Company's website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

In the late 1980s, the Company determined its core electric business was located in a region of the country where there was little growth in the demand for electricity. In order to maintain growth for shareholders, Otter Tail Power Company (as the Company was then known) began to explore opportunities for the acquisition and long-term ownership of nonelectric businesses. This strategy has resulted in steady revenue growth over the years. In 2001, the name of the Company was changed to "Otter Tail Corporation" to more accurately represent the broader scope of electric and nonelectric operations and the name "Otter Tail Power Company" was retained for use by the electric utility. In 2007, approximately 26% of the Company's consolidated operating revenues and approximately 45% of the Company's consolidated income came from electric operations.

The Company's strategy is straightforward: Reliable utility performance combined with growth opportunities at all its businesses provides long-term value. This includes growing the core electric utility business which provides a strong base of revenues, earnings and cash flows. In addition, the Company looks to its nonelectric operating companies to provide organic growth as well. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. The Company expects much of the growth in the next few years will come from major capital investment at existing companies. The Company also expects to grow through acquisition and adheres to strict guidelines when reviewing acquisition candidates. The Company's aim is to add companies that will produce an immediate positive impact on earnings and provide long-term growth potential. The Company believes owning well-run, profitable companies across different industries will bring more growth opportunities and more balance to results. In doing this, the Company also avoids concentrating business risk within a single industry. All of the operating companies operate under a decentralized business model with disciplined corporate oversight.

The Company assesses the performance of its operating companies over time, using the following criteria:

- ability to provide returns on invested capital that exceed the Company's weighted average cost of capital over the long term; and
- assessment of an operating company's business and potential for future earnings growth.

The Company is a committed long-term owner, and therefore does not acquire companies in pursuit of short-term gains. However, the Company will divest operating companies that do not meet these criteria over the long term.

Otter Tail Corporation and its subsidiaries conduct business in all 50 states and in international markets. The Company had approximately 4,099 full-time employees at December 31, 2007. The businesses of the Company have been classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

- Electric (the Utility) includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota under the name Otter Tail Power Company. In addition, the Utility is an active wholesale participant in the Midwest Independent Transmission System Operator (MISO) markets. Electric utility operations have been the Company's primary business since incorporation.
- Plastics consists of businesses producing polyvinyl chloride (PVC) and polyethylene (PE) pipe in the Upper Midwest and Southwest regions of the United States.
- Manufacturing consists of businesses in the following manufacturing activities: production of waterfront equipment, wind towers, material and handling trays and horticultural containers, contract machining, and metal parts stamping and fabrication. These businesses have manufacturing facilities in Minnesota, North Dakota, South Carolina, Missouri, California, Florida, Oklahoma and Ontario, Canada and sell products primarily in the United States.
- Health Services consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging services and rental of diagnostic medical imaging equipment to various medical institutions located throughout the United States.
- Food Ingredient Processing consists of Idaho Pacific Holdings, Inc. (IPH), which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries. Approximately 31% of IPH's sales are to customers outside of the United States.
- Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, wastewater and HVAC systems construction, transportation and energy services. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and six Canadian provinces.

The Company's corporate operating costs, which include corporate staff and overhead costs, the results of the Company's captive insurance company and other items are excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets.

The Company's electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation, and the Company's energy services operation is operated as a subsidiary of Otter Tail Corporation. Substantially all of the other businesses are owned by the Company's wholly-owned subsidiary, Varistar Corporation (Varistar).

The Company considers the following guidelines when reviewing potential acquisition candidates:

- Emerging or middle market company;
- Proven entrepreneurial management team that will remain after the acquisition;
- Preference for 100% ownership of the acquired company;
- Products and services intended for commercial rather than retail consumer use; and
- The potential to provide immediate earnings and future growth.

The Company continues to look for strategic acquisitions of additional businesses with emphasis on adding to existing operating companies and expects continued growth in this area.

On February 19, 2007 the Company’s wholly-owned subsidiary, ShoreMaster, Inc. (ShoreMaster), acquired the assets of the Aviva Sports product line for $2.0 million in cash. The Aviva Sports product line operates under Aviva Sports, Inc. (Aviva), a newly-formed wholly-owned subsidiary of ShoreMaster. The Aviva Sports product line is sold internationally and consists of products for consumer use in the pool, lake and yard, as well as commercial use at summer camps, resorts and large public swimming pools. The acquisitions of the Aviva Sports product line fits well with the other product lines of ShoreMaster, a leading manufacturer and supplier of waterfront equipment.

On May 15, 2007 the Company’s wholly-owned subsidiary, BTD Manufacturing, Inc. (BTD), acquired the assets of Pro Engineering, LLC (Pro Engineering) for $4.8 million in cash. Pro Engineering specializes in providing metal parts stampings to customers in the Midwest. The acquisition of Pro Engineering by BTD provides expanded growth opportunities for both companies.

The Company made significant investments in its existing operating companies in 2007 in order to drive organic growth in the coming years. Capital expenditures exclusive of acquisitions totaled $162 million, including expenditures for the Utility’s portion of the Langdon Wind Project and DMI Industries, Inc.’s (DMI) wind tower manufacturing facility near Tulsa, Oklahoma.

For a discussion of the Company’s results of operations, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” which is incorporated by reference to pages 19 through 35 of the Company’s 2007 Annual Report to Shareholders, filed as an Exhibit hereto.

(b) Financial Information About Industry Segments

The Company is engaged in businesses that have been classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. Financial information about the Company’s segments and geographic areas is incorporated by reference to note 2 of “Notes to Consolidated Financial Statements” on pages 47 and 48 of the Company’s 2007 Annual Report to Shareholders, filed as an Exhibit hereto.

(c) Narrative Description of Business

ELECTRIC

General

The Utility provides electricity to more than 129,000 customers in a 50,000 square mile area of Minnesota, North Dakota and South Dakota. The Company derived 26%, 28% and 32% of its consolidated operating revenues from the Electric segment for each of the three years ended December 31, 2007, 2006 and 2005, respectively. The Company derived 45%, 48% and 69% of its consolidated income from continuing operations from the Electric segment for each of the three years ended December 31, 2007, 2006 and 2005, respectively. The breakdown of retail revenues by state is as follows:

State	2007	2006
Minnesota	49.7%	51.5%
North Dakota	40.8	39.8
South Dakota	9.5	8.7
Total	100.0%	100.0%

The territory served by the Utility is predominantly agricultural. Although there are relatively few large customers, sales to commercial and industrial customers are significant. The following table provides a break down of electric revenues by customer category. All other sources include gross wholesale sales from Utility generation, net revenue from energy trading activity and sales to municipalities.

Customer category	2007	2006
Commercial	36.3%	35.6%
Residential	30.4	30.5
Industrial	23.1	23.0
All other sources	10.2	10.9
Total	100.0%	100.0%

Wholesale electric energy kilowatt-hours (kWh) sales were 28.6% of total kWh sales for 2007 and 41.0% for 2006. Wholesale electric energy kWh sales decreased by 40.7% between the years while revenue per kWh increased by 11.4%. Activity in the short-term energy market is subject to change based on a number of factors and it is difficult to predict the quantity of wholesale power sales or prices for wholesale power in the future.

With the inception of the MISO Day 2 markets in April 2005, MISO introduced two new types of contracts, virtual transactions and Financial Transmission Rights (FTR). Virtual transactions are of two types: Virtual Demand Bid, which is a bid to purchase energy in MISO’s Day-Ahead Market that is not backed by physical load, and Virtual Supply Offer which is an offer submitted by a market participant in the Day-Ahead Market to sell energy not supported by a physical injection or reduction in withdrawals in commitment by a resource. An FTR is a financial contract that entitles its holder to a stream of payments, or charges, based on transmission congestion charges calculated in MISO’s Day-Ahead Market. A market participant can acquire an FTR from several sources: the annual or monthly FTR allocation based on existing entitlements, the annual or monthly FTR auction, the FTR secondary market or a grant of an FTR in conjunction with a transmission service request. An FTR is structured to hedge a market participant’s exposure to uncertain cash flows resulting from congestion of the transmission system. In 2007, net revenues from virtual and FTR transactions represented 0.1% of total electric energy revenues compared with 1.4% in 2006. As the MISO markets have evolved and become more efficient, profits from virtual transactions have declined.

The aggregate population of the Utility's retail electric service area is approximately 230,000. In this service area of 423 communities and adjacent rural areas and farms, approximately 130,900 people live in communities having a population of more than 1,000, according to the 2000 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,527); Fergus Falls, Minnesota (13,471); and Bemidji, Minnesota (11,917). As of December 31, 2007 the Utility served 129,342 customers. This is an increase of 272 customers over December 31, 2006.

Capability and Demand

As of December 31, 2007 and 2006 the Utility had base load net plant capability as follows:

Base load net plant capability	2007	2006
Big Stone Plant	256,025kW	256,025kW
Coyote Station	149,450	149,450
Hoot Lake Plant	144,325	143,875
Total	549,800kW	549,350kW

The base load net plant capability for Big Stone Plant and Coyote Station constitutes the Utility's ownership percentages of 53.9% and 35%, respectively. The Utility owns 100% of the Hoot Lake Plant.

In addition to its base load capability, the Utility has combustion turbine and small diesel units owned or under contract, used chiefly for peaking and standby purposes, with a total capability of 145,098 kilowatt (kW), hydroelectric capability of 4,338 kW and 40,500 kW of wind generation under construction as part of the Langdon Wind Project. During 2007, the Utility generated about 72% of its retail kWh sales and purchased the balance.

On March 29, 2007 the Utility and Minnkota Power Cooperative entered into an agreement with FPL Energy to develop the Langdon Wind Project, a 159 megawatt (MW) wind farm south of Langdon, North Dakota which was completed in early 2008. The Utility's participation in the project includes the ownership of 27 wind turbines nameplate rated at 1.5 MW each and a 25-year power purchase agreement with Langdon Wind, LLC to purchase the electricity generated from 13 other wind turbines at the site. Construction of the 27 wind turbines owned by the Utility was completed in January 2008 adding approximately 12,000 kW of capacity to its net winter season generating capability and 9,000 kW of capacity to its net summer season generating capability, once all transmission arrangements are completed.

The Utility has arrangements to help meet its future base load requirements and continues to investigate other means for meeting such requirements. The Utility has an agreement to purchase 50,000 kW of year-round capacity through April 30, 2010. The Utility has agreements to purchase the output from wind generating facilities of approximately 40,500 kW (nameplate rating). The Utility has a direct control load management system which provides some flexibility to the Utility to effect reductions of peak load. The Utility, in addition, offers rates to customers which encourage off-peak usage.

The Utility traditionally experiences its peak system demand during the winter season. For the year ended December 31, 2007 the Utility experienced a system peak demand of 704,940 kW on February 2, 2007, which was also the highest all-time system peak demand (as reported to Mid-Continent Area Power Pool). Taking into account additional capacity available to it on February 2, 2007 under purchase power contracts (including short-term arrangements), as well as its own generating capacity, the Utility's capability of then meeting system demand, excluding reserve requirements computed in accordance with accepted industry practice, amounted to 846,275 kW (804,320 kW if reserve requirements are included). The Utility's additional capacity available under power purchase contracts (as described above), combined with generating capability and load management control capabilities, is expected to meet 2008 system demand, including industry reserve requirements.

Big Stone II

On June 30, 2005 the Utility and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant’s nominal generating capacity from 630 MW to between 500 and 580 MW. New procedural schedules have been established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

The Participation Agreement is an agreement to jointly develop, finance, construct, own (as tenants in common) and manage the Big Stone II Plant. The Participation Agreement includes provisions which obligate the parties to the agreement to obtain financing and pay their share of development, construction, operating and maintenance costs for the Big Stone II Plant. It also provides for the sharing of the plant output. Estimated construction costs for the plant including transmission are expected to be between $1.5 billion and $1.7 billion depending upon the size of unit constructed. The Participation Agreement provides that the Utility shall pay for and own approximately 120 MW share of the Big Stone II Plant and be entitled to a corresponding interest in the plant’s electrical output. The project participants included in the Participation Agreement a section covering withdrawal rights due to higher than anticipated project costs. Each participant has certain withdrawal rights exercisable at an agreed upon time. Under amendments to the Participation Agreement entered into in 2007, the agreed upon time is not later than 60 days after the later of receipt of i) the Minnesota Public Utilities Commission (MPUC) order regarding the Transmission Certificate of Need and ii) the Prevention of Significant Deterioration (PSD) air permit from the South Dakota Board of Minerals and Environment. The Participation Agreement establishes a Coordinating Committee and an Engineering and Operating Committee to manage the development, design, construction, operation and maintenance of the Big Stone II Plant.

The Operation and Maintenance Agreement designates the Utility as the operator of the Big Stone II Plant. As operator, the Utility is required to provide staff and resources for the development, design, financing, construction and operation of the Big Stone II Plant. The other project participants are each required to reimburse the Utility for their respective share of the costs relating to those activities. The Coordinating Committee and the Engineering and Operating Committee, which are made up of representatives of all project participants, are authorized to supervise the Utility in its role as operator.

The Joint Facilities Agreement provides for the transfer of certain real property and easements from the Big Stone I Plant owners to the Big Stone II Plant participants and for the shared use of certain equipment and facilities between the two plants. The Joint Facilities Agreement also allocates between the two plants the costs of operation and maintenance of the shared equipment and facilities.

The proposed project is intended to serve the participants’ native customer loads and is expected to be part of the Utility’s regulated rate base. The project will be nominally rated between 500 and 580 MW, and it will be coal fired. The proposed project is expected to meet air emission requirements as prescribed by the Environmental Protection Agency and the South Dakota Department of Environment and Natural Resources. Black & Veatch Corporation, a Kansas City based engineering firm, has been selected to do the plant design work and provide construction management services.

The participants have secured or are in the process of securing the permits required for construction and operation of the project, including the plant site permit, air emission permits and certificate of need and route permits for transmission. In addition, a federal environmental impact statement (EIS) is expected to yield a Record of Decision (ROD) in third quarter 2008. Applicants for all major permits have been filed and those that have not yet been acted on are scheduled for final agency action in 2008. For more information regarding the status of the permitting process, see "General Regulation" and "Environmental Regulation." Financial close, which requires the participants to provide binding financial commitments to support their share of costs, is to occur 90 days after the EIS ROD. The financial close is not currently expected until third quarter of 2008. No one can predict the exact outcome of any of these proceedings and there have been interveners in the permitting process. If the necessary approvals are received and plans progress, groundbreaking is expected to take place in 2009 with the plant in service by 2013.

As of December 31, 2007 the Utility capitalized $8.2 million in costs related to the planned construction of Big Stone II. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

Fuel Supply

Coal is the principal fuel burned at the Big Stone, Coyote and Hoot Lake generating plants. Coyote Station, a mine-mouth facility, burns North Dakota lignite coal. Hoot Lake and Big Stone plants burn western subbituminous coal.

The following table shows the sources of energy used to generate the Utility's net output of electricity for 2007 and 2006:

	2007		2006	
Sources	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated
Subbituminous Coal	2,273,799	67.1%	2,539,723	71.1%
Lignite Coal	1,032,449	30.5	981,478	27.5
Hydro and Renewables	20,537	.6	18,363	.5
Natural Gas and Oil	59,256	1.8	31,846	.9
Total	3,386,041	100.0%	3,571,410	100.0%

The Utility has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Kennecott Coal Sales Company	Wyoming subbituminous	December 31, 2010
Hoot Lake Plant	Kennecott Coal Sales Company	Wyoming subbituminous	December 31, 2010
Coyote Station	Dakota Westmoreland Corporation	North Dakota lignite	2016

The contract with Dakota Westmoreland Corporation has a 15-year renewal option subject to certain contingencies. It is the Utility's practice to maintain a minimum 30-day inventory (at full output) of coal at the Big Stone Plant and a 20-day inventory at the Coyote Station and Hoot Lake Plant.

Railroad transportation services to the Big Stone Plant are being provided under a common carrier rate by the BNSF Railway. The Company filed a complaint in regard to this rate with the Surface Transportation Board requesting the Board set a competitive rate. On January 27, 2006 the Surface Transportation Board issued a final decision dismissing the case. The co-owners of the Big Stone Plant appealed the Surface Transportation Board's decision to the U.S. Court of Appeals for the Eighth Circuit. Oral arguments were heard on the case on January 8, 2007, and on July 11, 2007, the co-owner's petition was denied by the Court. Railroad transportation services to the Hoot Lake Plant are being provided under a common carrier rate by the BNSF Railway. The common carrier rate is subject to a mileage-based methodology to assess a fuel surcharge. The basis for the fuel surcharge is the U.S. average price of retail on-highway diesel fuel. The fuel surcharge applies to both Hoot Lake and Big Stone plants. No coal transportation agreement is needed for the Coyote Station due to its location next to a coal mine.

The average cost of coal consumed (including handling charges to the plant sites) per million British Thermal Unit (BTU) for each of the three years 2007, 2006 and 2005 was $1.486, $1.419 and $1.339, respectively.

The Utility is permitted by the State of South Dakota to burn some alternative fuels, including tire-derived fuel and biomass, at the Big Stone Plant.

General Regulation

The Utility is subject to regulation of rates and other matters in each of the three states in which it operates and by the federal government for certain interstate operations.

A breakdown of electric rate regulation by each jurisdiction is as follows:

		2007		2006	
Rates	Regulation	% of Electric Revenues	% of kWh Sales	% of Electric Revenues	% of kWh Sales
MN retail sales	MN Public Utilities Commission	37.1%	34.5%	33.6%	30.8%
ND retail sales	ND Public Service Commission	30.4	25.8	25.9	22.7
SD retail sales	SD Public Utilities Commission	7.1	6.4	5.7	5.4
Transmission & wholesale	Federal Energy Regulatory Commission	25.4	33.3	34.8	41.1
		100.0%	100.0%	100.0%	100.0%

The Utility operates under approved retail electric tariffs in all three states it serves. The Utility has an obligation to serve any customer requesting service within its assigned service territory. Accordingly, the Utility has designed its electric system to provide continuous service at time of peak usage. The pattern of electric usage can vary dramatically during a 24-hour period and from season to season. The Utility's tariffs provide for continuous electric service and are designed to cover the costs of service during peak times. To the extent that peak usage can be reduced or shifted to periods of lower usage, the cost to serve all customers is reduced. In order to shift usage from peak times, the Utility has approved tariffs in all three states for lower rates for residential demand control and controlled service, in Minnesota and North Dakota for real-time pricing, and in North Dakota and South Dakota for bulk interruptible rates. Each of these specialized rates is designed to improve efficient use of the Utility facilities, while encouraging use of cost-effective electricity instead of other fuels and giving customers more control over the size of their electric bill. In all three states, the Utility has approved tariffs which allow qualifying customers to release and sell energy back to the Utility when wholesale energy prices make such transactions desirable.

The majority of the Utility's electric retail rate schedules now in effect provide for adjustments in rates based on the cost of fuel delivered to the Utility's generating plants, as well as for adjustments based on the cost of electric energy purchased by the Utility. Such adjustments are presently based on a two-month moving average in Minnesota and under the Federal Energy Regulatory Commission (FERC), a three-month moving average in South Dakota and a four-month moving average in North Dakota. These adjustments are applied to the next billing period after becoming applicable.

The following summarizes the material regulations of each jurisdiction applicable to the Utility's electric operations, as well as any specific electric rate proceedings during the last three years with the MPUC, the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and FERC. The Company's nonelectric businesses are not subject to direct regulation by any of these agencies.

Minnesota: Under the Minnesota Public Utilities Act, the Utility is subject to the jurisdiction of the MPUC with respect to rates, issuance of securities, depreciation rates, public utility services, construction of major utility facilities, establishment of exclusive assigned service areas, contracts and arrangements with subsidiaries and other affiliated interests, and other matters. The MPUC has the authority to assess the need for large energy facilities and to issue or deny certificates of need, after public hearings, within one year of an application to construct such a facility.

The Minnesota Department of Commerce (MNDOC) is responsible for investigating all matters subject to the jurisdiction of the MNDOC or the MPUC, and for the enforcement of MPUC orders. Among other things, the MNDOC is authorized to collect and analyze data on energy and the consumption of energy, develop recommendations as to energy policies for the governor and the legislature of Minnesota and evaluate policies governing the establishment of rates and prices for energy as related to energy conservation. The MNDOC acts as a state advocate in matters heard before the MPUC. The MNDOC also has the power, in the event of energy shortage or for a long-term basis, to prepare and adopt regulations to conserve and allocate energy.

The Utility has not had a significant rate proceeding before the MPUC since July 1987. The Utility filed a general rate case in Minnesota on October 1, 2007 requesting an interim rate increase of 5.4% effective November 30, 2007 and a final total rate increase of approximately 11% overall. However, the requested total increase includes a proposal to move the Utility's profits on wholesale transactions from a base-rate credit to a credit to the fuel clause adjustment (FCA). Therefore, the net effect of the rate increase requested is approximately 6.7%. The Utility's interim rate request was approved and will remain in effect for all Minnesota customers until the MPUC makes a final determination on the final request, which is expected by August 1, 2008. If the MPUC approves final rates that are lower than interim rates, the Utility will refund Minnesota customers the difference with interest.

Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota. The MNDOC may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. Since 1995, the Utility has recovered conservation related costs not included in base rates under Minnesota's Conservation Improvement Programs through the use of an annual recovery mechanism approved by the MPUC.

The MPUC requires the submission of a 15-year advance integrated resource plan by utilities serving at least 10,000 customers, either directly or indirectly, and generating at least 100 megawatts (MW) of electric power. The MPUC's findings of fact and conclusions regarding resource plans shall be considered prima facie evidence, subject to rebuttal, in certificate of need hearings, rate reviews and other proceedings. Typically, the filings are submitted every two years. The Utility submitted its most recent integrated resource plan on July 1, 2005. MPUC action on that plan is pending. The Utility's integrated resource plan includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchase power contracts and older coal-fired base-load generation units scheduled for retirement. It is expected that a final decision by the MPUC on the integrated resource plan will coincide with the MPUC final decision on the Certificate of Need for transmission line projects related to Big Stone II.

The MPUC requires the annual filing of a capital structure petition. In this filing the MPUC reviews and approves the capital structure for the Company. Once the petition is approved, the Company may issue securities without further petition or approval, provided the issuance is consistent with the purposes and amounts set forth in the approved capital structure petition. The Company's current capital structure petition is in effect until the Commission issues a new capital structure order for 2008. The Company expects to file its 2008 capital structure petition in March and expects to receive approval from the MPUC prior to May 31, 2008.

The Minnesota legislature has enacted a statute that favors conservation over the addition of new resources. In addition, it has mandated the use of renewable resources where new supplies are needed, unless the utility proves that a renewable energy facility is not in the public interest. It has effectively prohibited the building of new nuclear facilities. An existing environmental externality law requires the MPUC, to the extent practicable, to quantify the environmental costs associated with each method of electricity generation, and to use such monetized values in evaluating resource plans. The MPUC must disallow any nonrenewable rate base additions (whether within or outside of the state) or any rate recovery therefrom, and may not approve any nonrenewable energy facility in an integrated resource plan, unless the utility proves that a renewable energy facility is not in the public interest. The state has prioritized the acceptability of new generation with wind and solar ranked first and coal and nuclear ranked fifth, the lowest ranking.

In February 2007 the Minnesota legislature passed a renewable energy standard requiring the Utility to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards.

Under the Next Generation Energy Act of 2007 passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover charges incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to recover the costs of qualifying renewable energy projects to supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can now be authorized outside of a rate case proceeding provided that such renewable projects have received previous MPUC approval in an integrated resource plan or certificate of need proceeding before the MPUC. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses. The Utility has requested approval of a renewable resource rider that would allow recovery of eligible and prudently incurred costs for its qualifying renewable energy project investments. The proposed rider would cover the Minnesota jurisdictional portion of such eligible costs. The Utility expects to receive MPUC approval of its proposed rider in 2008.

In addition, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a tariff to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a certificate of need proceeding or certified by the

MPUC as a Minnesota priority transmission project. Such transmission cost recovery riders would allow a return on investments at the level approved in an electric utility's last general rate case. The Utility is also preparing to file a proposed rider to recover its share of costs of transmission infrastructure upgrades. The Utility currently expects to file its transmission cost recovery tariff and receive MPUC approval during 2008.

Pursuant to the Minnesota Power Plant Siting Act, the MPUC has been granted the authority to regulate the siting in Minnesota of large electric generating facilities in an orderly manner compatible with environmental preservation and the efficient use of resources. To that end, the MPUC is empowered, after an environmental impact study is conducted by the MNDOC and the Office of Administrative Law conducts contested case hearings, to select or designate sites in Minnesota for new electric power generating plants (50,000 kW or more) and routes for transmission lines (100 kilovolt (kV) or more) and to certify such sites and routes as to environmental compatibility.

The Utility and the coalition of six other electric providers filed an application for a Certificate of Need for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. Evidentiary hearings were conducted in December 2006 and all parties submitted legal briefs. The Administrative Law Judges (ALJs) on August 15, 2007 recommended approval of the Certificate of Need subject to potential conditions. The Utility and project participants addressed the ALJs' recommended potential conditions in an August 31, 2007 proposed settlement agreement with the MNDOC that was entered into the record of the Certificate of Need/Route Permit dockets. The MPUC had not acted on the applications or the proposed settlement agreement when Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. After the withdrawal, the MPUC on October 19, 2007 requested that the ALJs recommence proceedings in the matter, and that the remaining project participants file testimony describing and supporting a revised Big Stone II project. The remaining five participants filed testimony on November 13, 2007. The ALJs on December 3, 2007 issued an order refining the scope of the additional proceedings. Evidentiary hearings were held in January 2008. The Utility anticipates the ALJs will issue their report and recommendation in March 2008 and the MPUC will decide the matters in April 2008.

The Minnesota Legislature enacted the Minnesota Energy Security and Reliability Act in 2001. Its primary focus was to streamline the siting and routing processes for the construction of new electric generation and transmission projects. The bill also added to utility requirements for renewable energy and energy conservation. This legislation also changed the environmental review authority from the Environmental Quality Board to the MNDOC.

Planning studies have shown there will be significant electric load growth and more transmission will be necessary for renewable energy in the coming decade. This led to a joint transmission planning initiative among eleven utilities that own transmission lines in Minnesota and the surrounding region, called CapX 2020 — capacity expansion by 2020. On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kV transmission lines. These lines would help ensure continued reliable electricity service in Minnesota and the surrounding region by upgrading and expanding the high-voltage transmission network and providing capacity for more wind energy resources to be developed in southern and western Minnesota, eastern North Dakota and South Dakota. The proposed lines would span more than 600 miles and represent one of the largest single transmission initiatives in the region in several years. The MPUC is expected to decide if the lines are needed by early 2009. The MPUC would determine routes for the new lines in separate proceedings. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are complete (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading the project, and the Utility and eight other utilities are involved in permitting, building and financing. The Utility also serves as the development manager of the CapX 2020 Bemidji-Grand Rapids 230 kV transmission line. The Utility expects to file the Certificate of Need for this line by second quarter 2008. The Utility's 2008 — 2012 capital budgets include $67 million for CapX 2020 expenditures.

In December 2005 the MPUC issued an order denying the Utility's request to allow recovery of certain MISO-related costs through the FCA in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. The Utility recorded a $1.9 million reduction in revenue and a refund payable in December 2005 to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The MPUC's final order was issued on February 24, 2006 requiring jurisdictional investor-owned utilities in the state to participate with the MNDOC and other parties in a proceeding that would evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The February 24, 2006 order eliminated the refund provision from the December 2005 order and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the utility's next general rate case. As a result, the Utility recognized $1.9 million in revenue and reversed the refund payable in February 2006. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006.

In an order issued on December 20, 2006 the MPUC stated that except for schedule 16 and 17 administrative costs, discussed below, each petitioning utility may recover the charges imposed by the MISO for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of the utility's FCA from the period April 1, 2005 through a period of at least three years after the date of the order. The MPUC also ordered the utilities to refund schedule 16 and 17 costs collected through the FCA since the inception of MISO Day 2 Markets in April 2005 and stated that each petitioning utility may use deferred accounting for MISO schedule 16 and 17 costs incurred since April 1, 2005. That deferred accounting may continue for ongoing schedule 16 and 17 costs, without the accumulation of interest, until the earlier of March 1, 2009 or the utility's next electric rate case. According to the order, a utility may in its next general rate case seek to recover schedule 16 and 17 costs at an appropriate level of base rate recovery provided it shows that those costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. Also, a utility may seek to recover schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a general rate case, subject to final MPUC approval. Pursuant to this December 20, 2006 order, the Utility was ordered to refund $446,000 in MISO schedule 16 and 17 costs to Minnesota retail customers through the FCA over a twelve-month period beginning in January 2007. As of December 31, 2007 the Utility had refunded $407,000 of the $446,000 and deferred $855,000 in MISO schedule 16 and 17 costs. It has also requested recovery of the deferred costs and recovery of the ongoing costs in its pending general rate case. The Residential and Small Business Utilities Division of the Minnesota Office of Attorney General (MN RUD-OAG) has appealed the December 20, 2006 order to the Minnesota Court of Appeals.

The MNDOC and Utility identified two operational situations which are not covered in the approved method for allocating MISO costs contained in the final December 20, 2006 MPUC order discussed above. One relates to plants not expected to be available for retail but that produce energy in certain hours, resulting in wholesale sales. The other situation is the sale of Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007, the Utility determined its Minnesota customers' portion of costs associated with these situations to be $765,000. The data was provided to the MNDOC during the course of the MNDOC's review of the Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report). The Utility offered to refund $765,000 to its Minnesota customers to settle this and other issues raised by the MNDOC in the AAA Report docket before the MPUC and the MNDOC accepted the offer in October 2007 and recommended the MPUC include the refund in its final order. The Utility also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. The Utility agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted the Utility's refund offer and modifications and closed this docket on February 6,

2008. In December 2007, the Utility recorded a liability and a reduction to revenue of $805,000 for the amount of the refund offer and similar revenues collected subsequent to June 30, 2007.

In September 2004 the Company provided a letter to the MPUC summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. On November 30, 2004 the Utility filed a report with the MPUC responding to these claims. In 2005 the Energy Division of the MNDOC, the MN-RUD-OAG and the claimants filed comments in response to the report, to which the Utility filed reply comments. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the Utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The Utility filed these documents with the MPUC in the second quarter of 2006. The Utility received comments on its filings from the MNDOC and the claimants and filed reply comments in August 2006.

The MNDOC recommended accepting the revised Regulatory Compliance Plan and the chart of accounts definition. The Utility filed supplemental comments related to its Corporate Allocation Manual in November 2006. The Utility also agreed to file a general rate case in Minnesota on or before October 1, 2007. At a MPUC hearing on January 25, 2007 all remaining open issues were resolved. The MPUC accepted the Utility's compliance filing with minor changes, agreed to allow the Utility to calculate corporate cost allocations as proposed, determined not to conduct any further review at this time and required the Utility to include all of the Company's short-term debt in its calculations of allowance for funds used during construction. The Utility agreed to provide the MPUC the results of the current FERC operational audit when available, compare the corporate allocation method to a commonly accepted methodology in the next rate case, and provide the results of the Company's investigation relating to a 2007 hotline complaint. The Company recorded a non-cash charge of $3.3 million in 2006 related to the disallowance of a portion of capitalized costs of funds used during construction from the Utility's rate base. On December 12, 2007, the MPUC issued its order closing the investigation subject to the Company's continuing responsibility to file the report on its FERC operational audit as soon as it becomes available and subject to any further development of the record required in the Utility's pending general rate case.

North Dakota: The Utility is subject to the jurisdiction of the NDPSC with respect to rates, services, certain issuances of securities and other matters. The NDPSC periodically performs audits of gas and electric utilities over which it has rate setting jurisdiction to determine the reasonableness of overall rate levels. In the past, these audits have occasionally resulted in settlement agreements adjusting rate levels for the Utility. The North Dakota Energy Conversion and Transmission Facility Siting Act grants the NDPSC the authority to approve sites in North Dakota for large electric generating facilities and high voltage transmission lines. This Act is similar to the Minnesota Power Plant Siting Act described above and applies to proposed new electric power generating plants of 100,000 kW or more and proposed new transmission lines of more than 115 kV. The Utility is required to submit a ten-year plan to the NDPSC annually.

The NDPSC reserves the right to review the issuance of stocks, bonds, notes and other evidence of indebtedness of a public utility. However, the issuance by a public utility of securities registered with the Securities and Exchange Commission is expressly exempted from review by the NDPSC under North Dakota state law.

In February 2005, the Utility filed a petition with the NDPSC to seek recovery of certain MISO-related costs through the FCA. The NDPSC granted interim recovery through the FCA in April 2005, but similar to the decision of the MPUC, conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007 the NDPSC approved a settlement agreement between the Utility and an intervener representing several large industrial customers in North Dakota. When the MISO Day 2 energy market began in April 2005, the characterization of some of the Utility's energy costs changed, though the essential nature of those costs did not. Fuel and purchased energy costs incurred to serve retail customers are recoverable through the FCA in North Dakota. Under the approved settlement agreement, the Utility will refund to North Dakota customers the schedule 16 and 17 costs collected through the FCA since April 2005. The Utility can defer recognition of these costs and request recovery of them in its next general rate case. Purchase power expense was reduced and an offsetting regulatory asset was established for the amount of the refund. The refund amount of $493,000 was credited to North Dakota customers through the FCA beginning in October 2007. Also as part of the settlement, the Utility agreed to file a general rate case in North Dakota between November 1 and December 31, 2008. As of December 31, 2007 the Utility had deferred $576,000 in MISO schedule 16 and 17 costs in North Dakota pending the allowed recovery of those costs in its next rate case.

A filing in North Dakota for an advanced determination of prudence of Big Stone II was made by the Utility in November 2006. Evidentiary hearings were held in June 2007. The NDPSC decision was delayed because of the change in ownership of the project. The administrative law judge in the matter has scheduled supplemental hearings for April 2008.

South Dakota: Under the South Dakota Public Utilities Act, the Utility is subject to the jurisdiction of the SDPUC with respect to rates, public utility services, establishment of assigned service areas and other matters. The Utility is not currently subject to the jurisdiction of the SDPUC with respect to the issuance of securities. Under the South Dakota Energy Facility Permit Act, the SDPUC has the authority to approve sites in South Dakota for large energy conversion facilities (100,000 kW or more) and transmission lines of 115 kV or more. There have been no significant rate proceedings in South Dakota since November 1987.

The Utility and the coalition of six other electric providers filed an Energy Conversion Facility Siting Permit Application for Big Stone II with the SDPUC on July 21, 2005. The permit was granted by the SDPUC on July 14, 2006 but was appealed by a group of interveners on the basis that carbon dioxide concerns had not been adequately addressed. In February 2007 a South Dakota circuit court judge issued an opinion affirming the decision of the SDPUC to grant the siting permit for Big Stone II. The permit was appealed to the South Dakota Supreme Court. On January 16, 2008 the South Dakota Supreme Court unanimously affirmed the SDPUC's decision to grant Big Stone II project participants a site permit. A permit application for the South Dakota portion of the transmission line for Big Stone II was filed with the SDPUC on January 16, 2006 and was approved by the SDPUC on January 2, 2007.

The South Dakota Legislature recently passed and the Governor is expected to sign legislation that would, among other things, require that a public utility hold all owned or operated public utility assets in legal entities separate and segregated from non-utility subsidiaries, restrict the use of public utility secured debt to only public utility purposes, and restrict a public utility from extending credit to non-utility subsidiaries. The legislation provides a two-year grace period for compliance, and also authorizes the SDPUC to grant a waiver of any provision under certain circumstances. The Company does not believe the legislation, once enacted, will compel a change in corporate structure or change in its business model.

FERC: Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935, as amended. The FERC is an independent agency, which has jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one-day suspension period, subject to ultimate approval by the FERC.

On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time revenue sufficiency guarantee (RSG) charges that were not allocated to day-ahead virtual supply offers in accordance with MISO's Transmission and Energy Markets Tariff (TEMT) going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006 the FERC issued a Notice of Extension of Time, permitting MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund to customers the amounts due, with interest, from April 1, 2005 and the requirement to submit a compliance filing. The

Notice stated that the order on rehearing would provide the appropriate guidance regarding the timing of compliance filing. On October 26, 2006 the FERC issued an order on rehearing of the April 25, 2006 order, stating it would not require refunds related to real-time RSG charges that had not been allocated to day-ahead virtual supply offers in accordance with MISO's TEMT going back to the commencement of the MISO Day 2 market in April 2005. However, the FERC ordered prospective allocation of RSG charges to virtual transactions consistent with the TEMT to prevent future inequity and directed MISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs that virtual supply offers cause within 60 days of the October 26, 2006 order. On December 27, 2006 the FERC issued an order granting rehearing of the October 26, 2006 order.

On March 15, 2007 the FERC issued an order denying requests for rehearing of the RSG rehearing order dated October 27, 2006. In the March 15, 2007 order on rehearing, the FERC stated that its findings in the April 25, 2006 RSG order that virtual offers should share in the allocation of RSG costs, per the terms of the currently effective tariff, served as notice to market participants that virtual offers, for those market participants withdrawing energy, were liable for RSG charges. FERC clarified that the RSG rehearing order's waiver of refunds applies to the period before that order, from market start-up in April 2005 until April 24, 2006. After that date, virtual supply offers are liable for RSG costs and therefore, to the extent virtual supply offers were not assessed RSG costs, refunds are due for the period starting April 25, 2006.

On November 5, 2007 the FERC issued two orders related to the RSG proceeding. In the first order, the FERC accepted the MISO's April 17, 2007 RSG compliance filing to comply with the FERC's March 15, 2007 RSG order. The compliance order reinserted language requiring the actual withdrawal of energy by market participants, restored the MISO's original TEMT language allocating RSG costs to virtual transactions, revised the effective date for allocation to imports, provided an explanation of its efforts to reflect partial-hour revenue determinations in its software development, and revised several definitions.

The second related RSG order issued by FERC on November 5, 2007 was its order on rehearing on its April 25, 2006 order, in which it rejected the MISO's proposal to remove references to virtual supply from the TEMT provisions related to calculating RSG charges (FERC Docket Nos. ER04-691-084 and ER04-691-086). In this order, the FERC denied the requests for rehearing of the RSG second rehearing order (the Utility was one of the parties that sought rehearing) and FERC denied all requests for rehearing of the RSG compliance order.

In the RSG compliance order, the FERC rejected the MISO's proposal to allocate costs based on net virtual offers, i.e., virtual offers minus virtual bids, and clarified that the currently effective tariff, which allocates RSG costs to virtual supply offers, remains in effect.

In the RSG second rehearing order, the FERC clarified that for those market participants withdrawing energy, to the extent virtual supply offers were not assessed RSG costs, refunds were due for the period starting April 25, 2006.

The Utility recorded a $1.7 million ($1.0 million net-of-tax) charge to earnings in the first quarter of 2007 based on an internal estimate of the net impact of MISO reallocating RSG charges in response to the FERC order on rehearing. In May 2007, MISO informed affected market participants of the impact of reallocating charges based on its interpretation of the FERC order on rehearing. Based on MISO's interpretation of the order on rehearing, the Utility estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the Utility. Accordingly, the Utility revised its first quarter estimated charge of $1.7 million ($1.0 million net-of-tax) to zero in the second quarter of 2007. The Utility is awaiting FERC's response to MISO's December 5, 2007 RSG compliance filing and cannot determine what financial impact, if any, the filing will have on the Company's consolidated results of operations. However, MISO has stated that there will be no additional resettlement related to this matter.

The Division of Operation Audits of the FERC Office of Market Oversight and Investigations (OMOI) commenced an audit of the Utility's transmission practices in 2005. The purpose of the audit is to determine whether and how the Utility's transmission practices are in compliance with the FERC's applicable rules and regulations and tariff requirements and whether and how the implementation of the Utility's waivers from the requirements of Order No. 889 and Order No. 2004 restricts access to transmission information that would benefit the Utility's off-system sales. The Division of Operation Audits of the OMOI has not issued an audit report. The Company does not expect the results of the audit to have a material impact on the Company's consolidated financial statements.

The Comprehensive Energy Policy Act of 2005 (the 2005 Energy Act) signed into law in August 2005, substantially affected the regulation of energy companies, including the Utility. The 2005 Energy Act amended federal energy laws and provided the FERC with new oversight responsibilities. Among the important changes implemented as a result of this legislation were the following:

- The Public Utility Holding Company Act of 1935 (PUHCA) was repealed effective February 8, 2006. PUHCA significantly restricted mergers and acquisitions in the electric utility sector.
- FERC appointed the Electric Reliability Organization (ERO) formerly known as North American Electric Reliability Council (NERC) as an electric reliability organization to establish and enforce mandatory reliability rules regarding the interstate electric transmission system. On January 1, 2007 the ERO began operating.
- The FERC established incentives for transmission companies, such as performance based rates, recovery of costs to comply with reliability rules and accelerated depreciation for investments in transmission infrastructure.
- Federal support was made available for certain clean coal power initiatives, nuclear power projects and renewable energy technologies.

The Utility continues to follow the regulatory matters arising from the 2005 Energy Act and cannot predict with certainty the impact on its electric operations.

MAPP: The Utility participates in the Mid-Continent Area Power Pool (MAPP) generation reserve sharing pool, which operates in parts of eight states in the Upper Midwest and in three provinces in Canada.

MEMA: The Utility is a member of the Mid-Continent Energy Marketers Association (MEMA) which is an independent, non-profit trade association representing entities involved in the marketing of energy or in providing services to the energy industry. MEMA operates in the MAPP, MISO, Southwest Power Pool, PJM Interconnection, LLC and Southeast regions and was formed in 2003 as a successor organization of the Power and Energy Market of MAPP. Power pool sales are conducted continuously through MEMA in accordance with schedules filed by MEMA with the FERC.

MRO: The Utility is a member of the Midwest Reliability Organization (MRO). The MRO, a non-profit organization that replaced the MAPP Regional Reliability Council, is one of eight Regional Reliability Councils that comprise the NERC. The MRO is a voluntary organization committed to ensuring the reliability of the bulk power system in the Midwest part of North America. The MRO, through its balanced stakeholder board with independent oversight, operates independently from any member, market participant or operator, so that the standards developed and enforced by the MRO are fair and administered without undue influence from market participants. The MRO is approximately 40% larger in terms of net end use load than MAPP. The MRO region includes more than 40 members supplying approximately 280 million megawatt-hours to more than 20 million people. Its membership is comprised of municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations and independent power producers.

MISO: The Utility is a member of the MISO. As expressed in FERC Order No. 2000, FERC's view is that independent regional transmission organizations will benefit the public interest by enhancing the reliability of the electric grid and providing unbiased regional grid management, nondiscriminatory operation of the bulk power transmission system and open access to the transmission facilities under MISO's functional supervision. The MISO covers a broad region containing all or parts of 20 states and one Canadian province. The MISO began operational control of the Utility's transmission facilities above 100 kV on February 1, 2002 but the Utility continues to own and maintain its transmission assets. As the transmission provider and security coordinator for the region, the MISO seeks to optimize the efficiency of the interconnected system, provide regional solutions to regional planning needs and minimize risk to reliability through its security coordination, long-term regional planning, market monitoring, scheduling and tariff administration functions.

The MISO Energy Markets commenced operation on April 1, 2005. Through its Energy Markets, MISO seeks to develop options for energy supply, increase utilization of transmission assets, optimize the use of energy resources across a wider region and provide greater visibility of data. MISO aims to facilitate a more cost-effective and efficient use of the wholesale bulk electric system. The MISO Energy Market is intended to improve efficiency and price transparency, which may reduce the Utility's opportunity for traditional marketing profits. The effects of the MISO Energy Market on the Utility's retail customers, including costs to those customers, and the Utility's wholesale margins are expected to vary through the transition.

Other: The Utility is subject to various federal and state laws, including the Federal Public Utility Regulatory Policies Act and the Energy Policy Act of 1992, which are intended to promote the conservation of energy and the development and use of alternative energy sources, and the 2005 Energy Act described above.

Competition, Deregulation and Legislation

Electric sales are subject to competition in some areas from municipally owned systems, rural electric cooperatives and, in certain respects, from on-site generators and cogenerators. Electricity also competes with other forms of energy. The degree of competition may vary from time to time depending on relative costs and supplies of other forms of energy. The Utility may also face competition as the restructuring of the electric industry evolves.

The Company believes the Utility is well positioned to be successful in a more competitive environment. A comparison of the Utility's electric retail rates to the rates of other investor-owned utilities, cooperatives and municipals in the states the Utility serves indicates the Utility's rates are competitive. In addition, the Utility would attempt more flexible pricing strategies under an open, competitive environment.

Legislative and regulatory activity could affect operations in the future. The Utility cannot predict the timing or substance of any future legislation or regulation. There has been no legislative action regarding electric retail choice in any of the states where the Utility operates. The Minnesota legislature is considering legislation which would regulate holding companies doing business within the state that include in the ownership chain a public utility. The legislation would limit the non-utility assets of the holding company as a whole, to 25% of total assets. This legislation, if passed in its present form, could limit the Company's ability to maintain and grow its nonelectric businesses. The Company does not expect retail competition to come to the States of Minnesota, North Dakota or South Dakota in the foreseeable future.

The Utility is unable to predict the impact on its operations resulting from future regulatory activities, from future legislation or from future taxes that may be imposed on the source or use of energy.

Environmental Regulation

Impact of Environmental Laws: The Utility's existing generating plants are subject to stringent federal and state standards and regulations regarding, among other things, air, water and solid waste pollution. In the five years ended December 31, 2007 the Utility invested approximately $17.1 million in environmental control facilities. The 2008 construction budget includes approximately $9.4 million for environmental equipment for existing facilities. The Utility's share of environmental expenditures for the proposed Big Stone II Plant is estimated to be $133 million, including the cost of a joint scrubber, which will be shared between the current Big Stone Plant and the proposed Big Stone II Plant.

Air Quality: Pursuant to the Federal Clean Air Act of 1970 as amended (the Act), the United States Environmental Protection Agency (EPA) has promulgated national primary and secondary standards for certain air pollutants.

The primary fuels burned by the Utility's steam generating plants are North Dakota lignite coal and western subbituminous coal. Electrostatic precipitators have been installed at the principal units at the Hoot Lake Plant. Hoot Lake Plant unit 1 turbine generator, which is the smallest of the three coal-fired units at Hoot Lake Plant, was retired as of December 31, 2005. The Utility has retained the unit 1 boiler for use as a source of emergency heat. A fabric filter collects particulates from stack gases on Hoot Lake Plant unit 1. As a result, the Utility believes the units at the Hoot Lake Plant currently meet all presently applicable federal and state air quality and emission standards.

A major portion of the Big Stone Plant's electrostatic precipitator was replaced in 2002 with an Advanced Hybrid™ technology that was installed as part of a demonstration project co-funded by Department of Energy's National Energy Technology Laboratory Power Plant Improvement Initiative. The technology was designed to capture at least 99.99% of the fly ash particulates emitted from the boiler. Initial test data demonstrated the emissions design parameters were met. However, the plant experienced adverse operational performance of the technology and unacceptable balance-of-plant impacts. Even though Big Stone Plant co-owners replaced the remaining four precipitator fields with Advanced Hybrid™ technology in 2005, the technology continued to impose limits on plant output. The Big Stone Plant co-owners evaluated particulate emissions control technology options and decided to replace the demonstration project Advanced Hybrid™ technology with a pulse jet baghouse in 2007. The pulse jet baghouse replacement project was completed during the fall 2007 maintenance outage. The Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

The Coyote Station is equipped with sulfur dioxide removal equipment. The removal equipment—referred to as a dry scrubber—consists of a spray dryer, followed by a fabric filter, and is designed to desulfurize hot gases from the stack. The fabric filter collects spray dryer residue along with the fly ash. The Coyote Station is currently operating within all presently applicable federal and state air quality and emission standards.

The Act, in addressing acid deposition, imposed requirements on power plants in an effort to reduce national emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx).

The national SO2 emission reduction goals are achieved through a market-based system under which power plants are allocated "emissions allowances" that will require plants to either reduce their emissions or acquire allowances from others to achieve compliance. Each allowance is an authorization to emit one ton of sulfur dioxide. Sulfur dioxide emission requirements are currently being met by all of the Utility's generating facilities without the need to acquire other allowances for compliance.

The national NOx emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. Hoot Lake Plant unit 2 is governed by the phase one early opt-in provision until January 1, 2008. In order to meet the national NOx emission standards required at the Hoot Lake Plant unit 2 in 2008, the Utility plans to install low NOx burners and over-fire air in the first quarter of 2008, which will enable the unit to meet the annual average emission rate. The remaining generating units meet the NOx emission regulations that were adopted by the EPA in December 1996. All of the Utility's generating facilities met the NOx standards during 2007.

The EPA Administrator signed the final Interstate Air Quality Rule, also known as the Clean Air Interstate Rule, on March 10, 2005. EPA has concluded that SO2 and NOx are the chief emissions contributing to interstate transport of particulate matter less than 2.5 microns (PM2.5). EPA has also concluded that NOx emissions are the chief emissions contributing to ozone non-attainment. Twenty-three states and the District of Columbia were found to contribute to ambient air quality PM2.5 non-attainment in downwind states. On that basis, EPA is proposing to cap SO2 and NOx emissions in the designated states. Minnesota is included among the twenty-three states for emissions caps. Twenty-five states were found to contribute to downwind 8-hour ozone non-attainment. None of the states in the Utility's service territory are slated for NOx reduction for ambient air quality 8-hour ozone non-attainment purposes. Based on the Utility's assessment of the likely applicable requirements, Hoot Lake Plant units 2 and 3 must either reduce their NOx emissions to approximately 0.13 pounds per million BTU or purchase NOx allowances for those emissions in excess of that level beginning in 2009. NOx emissions control equipment was installed on Hoot Lake Plant unit 3 in 2006 at a cost of approximately $1.9 million. As noted above, additional NOx emission control equipment is slated for installation in 2008 on Hoot Lake Plant unit 2 at a similar cost. The Utility expects that the installation of NOx emission control equipment will allow Hoot Lake Plant units 2 and 3 to reduce the purchase of NOx allowances.

On June 15, 2005, EPA signed the Regional Haze Best Available Retrofit Technology (BART) rule. The rule requires emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. Hoot Lake Plant unit 3 and Big Stone Plant are units that are potentially subject to emission reduction requirements. The Minnesota Pollution Control Agency (MPCA) has determined that Hoot Lake Plant unit 3 is not subject to the BART rule. A similar determination has not been made for Big Stone Plant and it remains potentially subject to emission reduction requirements. The state rule revisions were due by January 2008, but South Dakota rule revisions are likely to be delayed. Given the regulatory uncertainties at this time, it is not possible to assess to what extent this regulation will impact the Utility.

The Act calls for EPA studies of the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and submitted reports to Congress. The Act required the EPA to make a finding as to whether regulation of emissions of hazardous air pollutants from fossil fuel-fired electric utility generating units is appropriate and necessary. On December 14, 2000 the EPA announced it affirmatively decided to regulate mercury emissions from electric generating units. The EPA published the proposed mercury rule on January 30, 2004. The proposal included two options for regulating mercury emission from coal-fired electric generating units. One option would set technology-based maximum achievable control technology standards under paragraph 111(d) of the Act. The other option embodies a market-based cap and trade approach to emissions reduction. The EPA published final rules in May 2005 based on the cap and trade approach. On October 28, 2005 the EPA announced a reconsideration of portions of the final rules. Final rules were published on June 9, 2006 that maintained the cap and trade approach. On February 8, 2008, the United States Court of Appeals for the D.C. Circuit granted petitions for review of the EPA rules and vacated the rules that would have allowed the EPA to regulate mercury emissions based on a cap and trade approach. Given the court's decision, future mercury regulatory requirements and the impact on the Utility are uncertain at this time.

In 1998, the EPA announced its New Source Review Enforcement Initiative targeting coal-fired utilities, petroleum refineries, pulp and paper mills and other industries for alleged violations of EPA's New Source Review rules. These rules require owners or operators that construct new major sources or make major modifications to existing sources to obtain permits and install air pollution control equipment at affected facilities. The EPA is attempting to determine if emission sources violated certain provisions of the Act by making major modifications to their facilities without installing state-of-the-art pollution controls. On January 2, 2001 the Utility received a request from the EPA, pursuant to Section 114(a) of the Act, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant. The Utility responded to that request. In March 2003 the EPA conducted a review of the plant's outage records as a follow-up to their January 2001 data request. A copy of the designated documents was provided to EPA on March 21, 2003. At this time the Utility cannot determine what, if any, actions will be taken by the EPA. The EPA issued changes to the existing New Source Review rules with respect to routine maintenance and repair and replacement activities in its Equipment Replacement Provision Rule on October 27, 2003. However, the U.S. Court of Appeals for the D.C. Circuit issued an order which stayed the effective date of the Equipment Replacement Provision rule pending judicial review. In a March 2006 decision the U.S. Court of Appeals for the D.C. Circuit struck down the EPA's Equipment Replacement Provision. The EPA petitioned the original three-judge panel to reconsider its ruling and, at the same time, petitioned all of the court's judges to rehear the panel's decision. In June 2006, the judges denied both requests. The Department of Justice, on behalf of EPA, and the Utility Air Regulatory Group filed a petition with the U.S. Supreme Court in November 2006 asking the Court to overturn the D.C. Circuit Court's decision to vacate the Equipment Replacement Provision. The petition was denied. On April 25, 2007, EPA issued its supplemental proposal on the New Source Review Emissions Increase Rule. A final rule is expected shortly.

On November 20, 2006, the Sierra Club notified the Utility and the two other Big Stone Plant co-owners of its intent to sue alleging violations of the PSD requirements of the Act at the Big Stone Plant with respect to three past plant activities. The Sierra Club stated that unless the matter is otherwise fully resolved, it intends to file suit in the applicable district courts any time 60 days after November 20, 2006. As of the date of this report on Form 10-K the Sierra Club has not filed suit in the applicable district courts. The Utility believes that the Big Stone Plant is in material compliance with all applicable requirements of the Act.

The Coyote Station is subject to certain emission limitations under the PSD program of the Act. The EPA and the North Dakota Department of Health reached an agreement to identify a process for resolving several issues relating to the modeling protocol for the state's PSD program. Modeling was completed and the results were submitted to the EPA for its review. On April 19, 2005 the North Dakota Department of Health held a Periodic Review Hearing relating to the PSD Air Quality Modeling Report that was submitted to the EPA. One of the Hearing Officer's Findings and Conclusion was that the air quality relating to impacts of SO2 emissions is being adequately protected and that at 2002-2003 SO2 emission levels the relevant Class I increments are not violated.

The issue of global climate change and the connection between global warming and increased levels of carbon dioxide (CO_2) -a greenhouse gas (GHG)-in the atmosphere is receiving increased attention. Combustion of fossil fuels for the generation of electricity is a major stationary source of CO_2 emissions in the United States and globally. The Utility is an owner or part-owner of three base-load, coal-fired electricity generating plants and four fuel-oil or natural gas-fired combustion turbine peaking plants with a combined generating capability of 679 MW. In 2007, these plants emitted approximately 4.2 million tons of $CO_{2.}$

The Utility monitors and evaluates the possible adoption of national, regional, or state climate change and GHG legislation or regulations that would affect electric utilities. Debate continues in Congress on the direction and scope of U.S. policy on climate change and regulation of GHGs. Although several bills have been introduced in Congress that would compel reductions in carbon dioxide emissions, there are presently no federal mandatory greenhouse gas reduction requirements. The likelihood of any federal mandatory carbon dioxide emissions reduction program being adopted in the near future, and the specific requirements of any such program, is uncertain. However, in April 2007, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate CO_2 and other greenhouse gases from automobiles as "air pollutants" under the Clean Air Act. The Supreme Court sent the case back to the EPA, which must conduct a rulemaking to determine whether greenhouse gas emissions contribute to climate change "which may reasonably be anticipated to endanger public health or welfare." While this case addressed a provision of the Clean Air Act related to emissions from motor vehicles, a parallel provision of the Clean Air Act applies to stationary sources such as electric generators. Unless the U.S. Congress enacts legislation directing otherwise, the EPA could begin to regulate such emissions.

Although standards have not been developed at the national level, several states and regional organizations are developing, or already have developed, state-specific or regional legislative initiatives to reduce GHG emissions through mandatory programs. In 2007, the state of Minnesota passed legislation regarding renewable energy portfolio standards that will require retail electricity providers to obtain 25% of the electricity sold to Minnesota customers from renewable sources by the year 2025. The Minnesota Legislature set a January 1, 2008 deadline for the MPUC to assign a carbon dioxide tax to electric generation. The legislation also set state targets for reducing fossil fuel use, included goals for reducing the state's output of greenhouse gases, and restricted importing electricity generated by new coal-fueled power plants. MPUC, in its order dated December 21, 2007, has established an estimate of future carbon dioxide regulation cost at between $4/ton and $30/ton emitted in 2012 and after.

The states of North Dakota and South Dakota currently have no proposed or pending legislation related to the regulation of GHGs, but North Dakota has a 10% renewable energy objective. As of the date of this report, a 10% renewable energy objective has passed both legislative chambers in South Dakota and is awaiting the Governor's signature.

While the eventual outcome of proposed and pending climate change legislation and GHG regulation is unknown, the Utility is taking steps to reduce its carbon footprint and mitigate levels of CO_2 emitted in the process of generating electricity for its customers through the following initiatives:

- Supply efficiency and reliability: Between 1990 and 2005, the Utility decreased its CO_2 intensity (lbs. of CO_2 /mwh generated) nearly 11%. The Utility plans to more than double that reduction by 2025. Big Stone II, the Utility proposed new generating plant is designed to incorporate supercritical pulverized coal technology that will increase plant efficiency by 20 percent and produce fly-ash that can replace cement in making concrete. In addition, transmission capacity above that which was needed for the plant was included in order to encourage regional wind energy development. The Utility's most recent integrated resource plan calls for the retirement of older coal units that generate up to 122 MW of electricity by 2017. This would be replaced with the best available technology, which would be more efficient and potentially would include carbon capture and sequestration technologies.

- Conservation: Since 1992 the Utility has helped our customers conserve more than 1 million mwh of electricity. That is roughly equivalent to the amount of electricity that 90,000 average homes would have used in a year. The Utility continues to educate customers about energy efficiency and demand-side management and to work with regulators to develop new programs and measurements. The Utility's integrated resource plan calls for an additional 98 mw of conservation impacts by 2020.

- Renewable energy: Since 2002 the Utility's customers have been able to purchase 100% of their electricity from wind generation through the Utility's TailWinds program. The MPUC has approved 160 MW of new wind generation in the most recent resource plan filing. Of that, 19.5 MW of purchased power agreements came on-line in December 2007 and 40.5 MW of owned wind resources were on-line by January 2008. Other projects are in the development phase and are expected to come on-line in the 2008 — 2010 time period. The Utility has purchased all the electricity generated by fourteen 1.5 MW wind turbines located in southeastern North Dakota since 2004. The Utility supports Minnesota's new law requiring 25% of the electricity sold to Minnesota customers be obtained from renewable resources by 2025, especially with its customer protection provisions. This new law was based on the MPUC's Wind Integration Study, which assumed in its baseline the construction of the Big Stone II power plant and associated transmission. The Utility supports North Dakota's renewable energy objective that 10% of all retail electricity sold within the state by the year 2015 be obtained from renewable energy and recycled energy sources.

- Other: The Utility will continue to participate as a member of EPA's SF_6 (sulfur hexafluoride) Emission Reduction Partnership for Electric Power Systems program. The partnership proactively is targeting a reduction in emissions of SF_6, a potent greenhouse gas. SF_6 has a global-warming potential 23,900 times that of CO_2. The Utility is involved in a pilot project to use methane from a municipal waste water treatment plant to generate electricity and is also studying the potential for other methane-related projects. Methane has a global-warming potential 20 times that of CO_2. The Utility participates in carbon sequestration research through the Plains CO_2 Reduction Partnership (PCOR) through the University of North Dakota's Energy and Environment Research Center. The PCOR Partnership is a collaborative effort of more than 50 public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing anthropogenic CO_2 emissions from stationary sources in the central interior of North America.

While the future financial impact of any proposed or pending climate change legislation or regulation of GHG emissions is unknown at this time, any capital and operating costs incurred for additional pollution control equipment or CO_2 emission reduction measures, such as the cost of sequestration or purchasing allowances, or offset credits, or the imposition of a carbon tax at the state or federal level could materially adversely affect the Company's future results of operations, cash flows, and possibly financial condition, unless such costs could be recovered through regulated rates and/or future market prices for energy.

Water Quality: The Federal Water Pollution Control Act Amendments of 1972, and amendments thereto, provide for, among other things, the imposition of effluent limitations to regulate discharges of pollutants, including thermal discharges, into the waters of the United States, and the EPA has established effluent guidelines for the steam electric power generating industry. Discharges must also comply with state water quality standards.

On February 16, 2004 the EPA Administrator signed the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures for certain existing facilities. Hoot Lake Plant is the Utility's only facility that could be impacted by this rule. On January 25, 2007 the U.S. Court of Appeals for the Second Circuit remanded portions of the rule to EPA. The Utility has completed an information collection program for the Hoot Lake Plant cooling water intake structure, but given the Court decision the Utility is uncertain of the impact on the facility at this time.

The Utility has all federal and state water permits presently necessary for the operation of the Coyote Station, the Big Stone Plant and the Hoot Lake Plant. The Utility owns five small dams on the Otter Tail River, which are subject to FERC licensing requirements. A license for all five dams was issued on December 5, 1991. Total nameplate rating (manufacturer's expected output) of the five dams is 3,450 kW.

Solid Waste: Permits for disposal of ash and other solid wastes have either been issued or are under renewal for the Coyote Station, the Big Stone Plant and the Hoot Lake Plant.

At the request of the MPCA, the Utility has an ongoing investigation at its former, closed Hoot Lake Plant ash disposal sites. The MPCA continues to monitor site activities under their Voluntary Investigation and Cleanup Program. The Utility provided a revised focus feasibility study for remediation alternatives to the MPCA in October 2004. The Utility and the MPCA have reached an agreement identifying the remediation technology and the Utility completed the projects in 2006. The effectiveness of the remediation is currently under evaluation.

The EPA has promulgated various solid and hazardous waste regulations and guidelines pursuant to, among other laws, the Resource Conservation and Recovery Act of 1976, the Solid Waste Disposal Act Amendments of 1980 and the Hazardous and Solid Waste Amendments of 1984, which provide for, among other things, the comprehensive control of various solid and hazardous wastes from generation to final disposal. The States of Minnesota, North Dakota and South Dakota have also adopted rules and regulations pertaining to solid and hazardous waste. To date, the Utility has incurred no significant costs as a result of these laws. The future total impact on the Utility of the various solid and hazardous waste statutes and regulations enacted by the federal government or the States of Minnesota, North Dakota and South Dakota is not certain at this time.

In 1980, the United States enacted the Comprehensive Environmental Response, Compensation and Liability Act, commonly known as the Federal Superfund law, which was reauthorized and amended in 1986. In 1983, Minnesota adopted the Minnesota Environmental Response and Liability Act, commonly known as the Minnesota Superfund law. In 1988, South Dakota enacted the Regulated Substance Discharges Act, commonly known as the South Dakota Superfund law. In 1989, North Dakota enacted the Environmental Emergency Cost Recovery Act. Among other requirements, the federal and state acts establish environmental response funds to pay for remedial actions associated with the release or threatened release of certain regulated substances into the environment. These federal and state Superfund laws also establish liability for cleanup costs and damage to the environment resulting from such release or threatened release of regulated substances. The Minnesota Superfund law also creates liability for personal injury and economic loss under certain circumstances. The Utility is unable to determine the total impact of the Superfund laws on its operations at this time but has not incurred any significant costs to date related to these laws. The Utility is not presently named as a potentially responsible party under the federal or state Superfund laws.

Capital Expenditures

The Utility is continually expanding, replacing and improving its electric facilities. During 2007, approximately $104 million was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2007 gross electric property additions, including construction work in progress, were approximately $253.7 million and gross retirements were approximately $65.6 million.

The Utility estimates that during the five-year period 2008-2012 it will invest approximately $759 million for electric construction, which includes $336 million for its share of expected expenditures for construction of the planned Big Stone II electric generating plant and related transmission assets if all necessary permits and approvals are granted on a timely basis. Other significant portions of the 2008-2012 capital budgets include wind generation projects and upgrades and extensions to the Utility’s transmission system.

Franchises

At December 31, 2007 the Utility had franchises to operate as an electric utility in all but four incorporated municipalities that it serves. All franchises are nonexclusive and generally were obtained for 20-year terms, with varying expiration dates. No franchises are required to serve unincorporated communities in any of the three states that the Utility serves. The Utility believes that its franchises will be renewed prior to expiration.

Employees

At December 31, 2007 the Utility had approximately 676 equivalent full-time employees. A total of 416 employees are represented by local unions of the International Brotherhood of Electrical Workers. These labor contracts were renewed in the fall of 2005 and have expiration dates in the fall of 2008 and 2009. The Utility has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

PLASTICS

General

Plastics consist of businesses producing PVC and PE pipe. The Company derived 12%, 15% and 16% of its consolidated operating revenues from the Plastics segment for each of the three years ended December 31, 2007, 2006 and 2005, respectively. The Company derived 15%, 28% and 26% of its consolidated income from continuing operations from the Plastics segment for each of the three years ended December 31, 2007, 2006 and 2005, respectively.

The following is a brief description of these businesses:

Northern Pipe Products, Inc. (Northern Pipe), located in Fargo, North Dakota, manufactures and sells PVC and PE pipe for municipal water, rural water, wastewater, storm drainage systems and other uses in the Northern, Midwestern and Western regions of the United States as well as Canada. Production facilities for PVC pipe are located in Fargo, North Dakota and Hampton, Iowa. The production facility for PE pipe is located in Hampton, Iowa.

Vinyltech Corporation (Vinyltech), located in Phoenix, Arizona, manufactures and sells PVC pipe for municipal water, wastewater, water reclamation systems and other uses in the Western, Southwestern and South-central regions of the United States.

Together these companies have the capacity to produce approximately 220 million pounds of PVC and PE pipe annually.

Customers

The PVC and PE pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for the PVC and PE pipe products consist primarily of wholesalers and distributors throughout the Upper Midwest, Southwest and Western United States.

Competition

The plastic pipe industry is highly fragmented and competitive, due to the large number of producers, the small number of raw material suppliers and the fungible nature of the product. Due to shipping costs, competition is usually regional, instead of national, in scope. The principal areas of competition are a combination of price, service, warranty and product performance. Northern Pipe and Vinyltech compete not only against other plastic pipe manufacturers, but also ductile iron, steel, concrete and clay pipe producers. Pricing pressure will continue to affect operating margins in the future.

Northern Pipe and Vinyltech intend to continue to compete on the basis of their high quality products, cost-effective production techniques and close customer relations and support.

Manufacturing and Resin Supply

PVC pipe is manufactured through a process known as extrusion. During the production process, PVC compound (a dry powder-like substance) is introduced into an extrusion machine, where it is heated to a molten state and then forced through a sizing apparatus to produce the pipe. The newly extruded pipe is then pulled through a series of water cooling tanks, marked to identify the type of pipe and cut to finished lengths. Warehouse and outdoor storage facilities are used to store the finished product. Inventory is shipped from storage to customers mainly by common carrier.

The PVC resins are acquired in bulk and shipped to point of use by rail car. Over the last several years, there has been consolidation in PVC resin producers. There are a limited number of third party vendors that supply the PVC resin used by Northern Pipe and Vinyltech. Two vendors provided approximately 95% and 99% of total resin purchases in 2007 and 2006, respectively. The supply of PVC resin may also be limited due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which is subject to risk of damage to the plants and potential shutdown of resin production because of exposure to hurricanes that occur in that part of the United States. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could disrupt the ability of the Plastics segment to manufacture products, cause customers to cancel orders or require incurrence of additional expenses to obtain PVC resin from alternative sources, if such sources were available. Both Northern Pipe and Vinyltech believe they have good relationships with their key raw material vendors.

Due to the commodity nature of PVC resin and PVC pipe and the dynamic supply and demand factors worldwide, historically the markets for both PVC resin and PVC pipe have been very cyclical with significant fluctuations in prices and gross margins.

Capital Expenditures

Capital expenditures in the Plastics segment typically include investments in extrusion machines, land and buildings and management information systems. During 2007, capital expenditures of approximately $3.3 million were made in the Plastics segment. Total capital expenditures for the five-year period 2008-2012 are estimated to be approximately $21 million. Estimated capital expenditures include approximately $10 million for plant expansion at both plants. Vinyltech's plant expansion will include a new resin-blending system and two additional extrusion lines which will increase production capacity by 40% after completion in 2008. Northern Pipe has planned the addition of an extrusion line to produce large-diameter PVC pipe at its Hampton, Iowa plant. When completed in the fall of 2008, the expansion will increase production capacity by more than 25%.

Employees

At December 31, 2007 the Plastics segment had approximately 185 full-time employees.

MANUFACTURING

General

Manufacturing consists of businesses engaged in the following activities: production of waterfront equipment, wind towers, material and handling trays and horticultural containers, contract machining and metal parts stamping and fabrication.

The Company derived 31%, 28% and 25% of its consolidated operating revenues from the Manufacturing segment for each of the three years ended December 31, 2007, 2006 and 2005, respectively. The Company derived 29%, 26% and 14% of its consolidated income from continuing operations from the Manufacturing segment for each of the three years ended December 31, 2007, 2006 and 2005, respectively. The following is a brief description of each of these businesses:

BTD Manufacturing, Inc., with headquarters located in Detroit Lakes, Minnesota, is a metal stamping and tool and die manufacturer that provides its services mainly to customers in the Midwest. BTD stamps, fabricates, welds and laser cuts metal components according to manufacturers' specifications primarily for the recreation vehicle, gas fireplace, health and fitness and enclosure industries.

DMI Industries, Inc., with headquarters located in West Fargo, North Dakota, engineers and manufactures wind towers and other heavy metal fabricated products. DMI has manufacturing facilities in West Fargo, North Dakota; Tulsa, Oklahoma; and Fort Erie, Ontario, Canada. DMI has a wholly-owned subsidiary, DMI Canada, Inc. located in Fort Erie, Ontario, Canada.

ShoreMaster, Inc., with headquarters in Fergus Falls, Minnesota, produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks to full marina systems that are marketed throughout the United States. ShoreMaster has four wholly-owned subsidiaries, Galva Foam Marine Industries, Inc., Shoreline Industries, Inc., Aviva Sports, Inc., and ShoreMaster Costa Rica Limitada. ShoreMaster has manufacturing facilities located in Fergus Falls and Pine River, Minnesota; Adelanto, California; Camdenton and Montreal, Missouri; and St. Augustine, Florida.

T. O. Plastics, Inc. (T.O. Plastics), located in Minneapolis and Clearwater, Minnesota; and Hampton, South Carolina; manufactures and sells thermoformed products for the horticulture industry throughout the United States. In addition, T. O. Plastics produces products such as clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts for other industries.

Competition

The various markets in which the Manufacturing segment entities compete are characterized by intense competition from both foreign and domestic manufacturers. These markets have many established manufacturers with broader product lines, greater distribution capabilities, greater capital resources and larger marketing, research and development staffs and facilities than the Company’s manufacturing entities.

The Company believes the principal competitive factors in its Manufacturing segment are product performance, quality, price, ease of use, technical innovation, cost effectiveness, customer service and breadth of product line. The Company’s manufacturing entities intend to continue to compete on the basis of high-performance products, innovative technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

Raw Materials Supply

The companies in the Manufacturing segment use a variety of raw materials in the products they manufacture, including steel, aluminum, resin and concrete. Both pricing increases and availability of these raw materials are concerns of companies in the Manufacturing segment. The companies in the Manufacturing segment attempt to pass the increases in the costs of these raw materials on to their customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative affect on profit margins in the Manufacturing segment.

Backlog

The Manufacturing segment has backlog in place to support 2008 revenues of approximately $295 million compared with $241 million one year ago.

Legislation

The demand for wind towers manufactured by DMI depends in part on the existence of either renewable portfolio standards or a federal production tax credit for wind energy. Renewable portfolio standards or objectives exist in approximately one-half of the states. A federal production tax credit is in place through December 31, 2008.

Capital Expenditures

Capital expenditures in the Manufacturing segment typically include additional investments in new manufacturing equipment or expenditures to replace worn-out manufacturing equipment. Capital expenditures may also be made for the purchase of land and buildings for plant expansion and for investments in management information systems. During 2007, capital expenditures of approximately $43 million were made in the Manufacturing segment driven mainly by the DMI expansion project in Tulsa, Oklahoma. Total capital expenditures for the Manufacturing segment during the five-year period 2008-2012 are estimated to be approximately $80 million. This investment is to replace existing capacity with new technology and processes, as well as the addition of machinery capacity at existing locations.

Employees

At December 31, 2007 the Manufacturing segment had approximately 1,663 full-time employees.

HEALTH SERVICES

General

Health Services consists of the DMS Health Group, which includes businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging services, and rental of diagnostic medical imaging equipment.

The Company derived 10%, 12% and 13% of its consolidated operating revenues from the Health Services segment for each of the three years ended December 31, 2007, 2006 and 2005, respectively. The Company derived 3%, 4% and 7% of its consolidated income from continuing operations from the Health Services segment for each of the three years ended December 31, 2007, 2006 and 2005, respectively. The companies comprising the DMS Health Group that deliver diagnostic imaging and healthcare solutions across the United States include:

DMS Health Technologies, Inc. (DMSHT), located in Fargo, North Dakota, sells and services diagnostic medical imaging equipment, cardiac and other patient monitoring equipment, defibrillators, EKGs and related medical supplies and accessories and provides ongoing service maintenance. DMSHT sells radiology equipment primarily manufactured by Philips Medical Systems (Philips), a large multi-national company based in the Netherlands. Philips manufactures fluoroscopic, radiographic and vascular equipment, along with ultrasound, computerized tomography (CT), magnetic resonance imaging (MR), positron emission tomography (PET), PET/CT and cardiac cath labs. The dealership agreement with Philips can be terminated on 180 days written notice by either party for any reason and can be terminated by Philips if certain compliance requirements are not met. DMSHT is also a supplier of medical film and related accessories. DMSHT markets mainly to hospitals, clinics and mobile imaging service companies.

DMS Imaging, Inc. (DMSI), a subsidiary of DMSHT located in Fargo, North Dakota, operates diagnostic medical imaging equipment, including CT, MRI, PET and PET/CT and provides nuclear medicine and other similar radiology services to hospitals, clinics, long-term care facilities and other medical providers. Regional offices are located in Minneapolis, Minnesota; Los Angeles, California; and Sioux Falls, South Dakota. DMS Imaging, Inc. provides services through four different business units:

- DMS Imaging — provides shared diagnostic medical imaging services (primarily mobile) for MR, CT, nuclear medicine, PET, PET/CT, ultrasound, mammography and bone density analysis.
- DMS Interim Solutions — offers interim and rental options for diagnostic imaging services.
- DMS MedSource Partners — develops long-term relationships with healthcare providers to offer dedicated in-house diagnostic imaging services.
- DMS Portable X-Ray — delivers portable x-ray, ultrasound and electrocardiography services to nursing homes and other facilities.

Combined, the DMS Health Group covers the three basics of the medical imaging industry: (1) ownership and operation of the imaging equipment for healthcare providers; (2) sale, lease and/or maintenance of medical imaging equipment and related supplies; and (3) scheduling, billing and administrative support of medical imaging services.

Regulation

The healthcare industry is subject to extensive federal and state regulations relating to licensure, conduct of operation, ownership of facilities, payment of services and expansion or addition of facilities and services.

The federal Anti-Kickback Statute prohibits persons from knowingly and willfully soliciting, receiving, offering or providing remuneration, directly or indirectly, to induce the referral of an individual or the furnishing or arranging for a good or service for which payment may be made under a federal healthcare program such as Medicare or Medicaid. Several states have similar statutes. The term “remuneration” has been broadly interpreted to include anything of value, including, for example, gifts, discounts, credit arrangements, payments of cash, waiver of payments and ownership interests. Penalties for violating the Anti-Kickback Statute can include both criminal and civil sanctions as well as possible exclusion from participating in Medicare and other federal healthcare programs.

The Ethics and Patient Referral Act of 1989 (Stark Law) prohibits a physician from making referrals for certain designated health services payable under Medicare, including services provided by the Health Services companies, to an entity with which the physician has a financial relationship, unless certain exceptions apply. The Stark Law also prohibits an entity from billing for designated health services pursuant to a prohibited referral. A person who engages in a scheme to violate the Stark Law or a person who presents a claim to Medicare in violation of the Stark Law may be subject to civil fines and possible exclusion from participation in federal healthcare programs. Several states have similar statutes, the violation of which can result in civil fines and possible exclusion from state healthcare programs. The Center for Medicare and Medicaid Services (CMS) is currently considering additional modifications to the Stark Law that may further limit the ability of physicians to provide certain imaging services in their practices.

The federal False Claims Act imposes liability on those who knowingly present or cause to be presented a false or fraudulent claim for payment to the federal government. “Knowingly” has been defined to include actions in deliberate ignorance and reckless disregard of the truth or falsity of such information. A suit under the False Claims Act can be brought directly by the United States Department of Justice, or can be brought by a “whistleblower.” A whistleblower brings suit on behalf of themselves and the United States, and the whistleblower is awarded a percentage of any recovery. Conduct that has given rise to False Claims Act liability includes but is not limited to current and past failures to comply with technical Medicare and Medicaid billing requirements, failure to comply with certain Medicare documentation requirements, and failure to comply with Medicare physician supervision requirements. Violations of the Stark Law and Anti-Kickback Statute have also served as the basis of False Claims Act liability. Many states have adopted or are seeking to adopt state false claims act laws modeled on the federal statute.

The Health Insurance Portability and Accountability Act of 1996 (HIPAA) created federal crimes related to healthcare fraud and to making false statements related to healthcare matters. HIPAA prohibits knowingly and willfully executing a scheme to defraud any healthcare benefit program including a program involving private payors. Further, HIPAA prohibits knowingly and willfully falsifying, concealing or covering up a material fact or making any materially false statement in connection with the delivery of or payment for healthcare benefits or services.

In some states a certificate of need or similar regulatory approval is required prior to the acquisition of high-cost capital items or services, including diagnostic imaging systems or the provision of diagnostic imaging services by companies or its customers. Certificate of need laws were enacted to contain rising healthcare costs by preventing unnecessary duplication of health resources.

DMSI maintains Independent Diagnostic Testing Facilities (IDTFs) that enroll in the Medicare program as participating Medicare suppliers, so that they may receive reimbursement directly from the Medicare program for services provided to Medicare beneficiaries. In November 2007, the CMS published final rules effective in 2008 that increase oversight of IDTFs and ensure quality care for Medicare beneficiaries. These regulations delineate certain stringent performance standards for IDTFs including standards for physical facilities, patient privacy, technician qualifications, insurance, equipment inspections, reporting changes to CMS, physician supervision, and manner in which IDTFs are defined and enrolled in Medicare. These standards also include a provision prohibiting certain staff or space sharing arrangements.

The final rules published as part of the 2008 Medicare Physician Fee Schedule also alter the scope of the federal anti-markup rule for diagnostic tests, a federal law which delineates instances when certain providers must treat certain technical and professional imaging procedures as purchased diagnostic tests. Providers are prohibiting from “marking-up” the price of the purchased tests to Medicare. The effective date of these changes has been delayed until January 1, 2009 for diagnostic imaging tests, but their eventual implementation, as well as ambiguities and uncertainties in the interpretation of the rules, may alter the expectations and operations of some of DMS’s clients and provide some disincentives to operate imaging services within their medical practices.

Additional federal and state regulations that the Health Services companies are subject to include state laws that prohibit the practice of medicine by non-physicians and prohibit fee-splitting arrangements involving physicians; Federal Food and Drug Administration requirements; state licensing and certification requirements; and federal and state laws governing diagnostic imaging and therapeutic equipment. Courts and regulatory authorities have not fully interpreted a significant number of the current laws and regulations.

The Health Services companies continue to monitor developments in healthcare law. The Health Services companies believe their operations comply with these laws and they are prepared to modify their operations from time to time as the legal and regulatory environment changes. However, there can be no assurances that the Health Services companies will always be able to modify their operations to address changes in the legal and regulatory environment without any adverse effect to their financial performance. The consequences of failing to comply with applicable laws can be severe. Laws such as the Anti-Kickback Statute and HIPAA carry criminal penalties. In many instances violations of applicable law can result in substantial fines and damages. Moreover, in some cases violations of applicable law can result in exclusion in participation in federal and state healthcare programs. If any of the Health Services companies were excluded from participation in federal or state healthcare programs, our customers who participate in those programs could not do business with us.

Reimbursement

The companies in the Health Services segment derive significant revenue from direct billings to customers and third-party payors such as Medicare, Medicaid, managed care and private health insurance companies for their diagnostic imaging services. The Health Services' customers are primarily healthcare providers who receive the majority of their payments from third-party payors. Payments by third-party payors to such healthcare providers depend, in part, upon their patients' health insurance policies.

New Medicare regulations reduced 2006 Medicare reimbursement for certain imaging services performed on contiguous body parts during the same day. In addition, the Deficit Reduction Act of 2005 (the DRA) limits reimbursement for imaging services provided in physician offices and in free-standing imaging centers to the reimbursement amount for that same service when provided in a hospital outpatient department. This DRA provision impacts a small number of imaging services provided by the Health Services segment. Federal and state legislatures may seek additional cuts in Medicare and Medicaid programs that could impact the value of the services provided by the Health Services segment.

Competition

The market for selling, servicing and operating diagnostic imaging services, patient monitoring equipment and imaging systems is highly competitive. In addition to direct competition from other providers of items and services similar to those offered by the Health Services companies, the companies within Health Services compete with free-standing imaging centers and health care providers that have their own diagnostic imaging systems, as well as with equipment manufacturers that sell imaging equipment directly to healthcare providers for permanent installation. Some of the direct competitors, which provide contract MR and PET/CT services, have access to greater financial resources than the Health Services companies. In addition, some of Health Services' customers are capable of providing the same services to their patients directly, subject only to their decision to acquire a high-cost diagnostic imaging system, assume the financial and technology risk, and employ the necessary technologists, rather than obtain the services from the Health Services company. The Health Services companies may also experience greater competition in states that currently have certificate of need laws if such laws were repealed, thereby reducing barriers to entry and competition in that state. The Health Services companies compete against other similar providers on the basis of quality of services, quality and magnetic field strength of imaging systems, relationships with health care providers, knowledge and service quality of technologists, price, availability and reliability.

Environmental, Health or Safety Laws

PET, PET/CT and nuclear medicine services require the use of radioactive material. While this material has a short life and quickly breaks down into inert, or non-radioactive substances, using such materials presents the risk of accidental environmental contamination and physical injury. Federal, state and local regulations govern the storage, use and disposal of radioactive material and waste products. The Company believes that its safety procedures for storing, handling and disposing of these hazardous materials comply with the standards prescribed by law and regulation; however the risk of accidental contamination or injury from those hazardous materials cannot be completely eliminated. The companies in the Health Services segment have not had any material expenses related to environmental, health or safety laws or regulations.

Capital Expenditures

Capital expenditures in this segment principally relate to the acquisition of diagnostic imaging equipment used in the imaging business. During 2007, capital expenditures of approximately $5 million were made in the Health Services segment. Total capital expenditures during the five-year period 2008-2012 are estimated to be approximately $11 million. Operating leases are also used to finance the acquisition of medical equipment used by Health Services companies. Current operating lease commitments during the five-year period 2008-2012 are estimated to be $99 million.

Employees

At December 31, 2007 the Health Services segment had approximately 408 full-time employees.

FOOD INGREDIENT PROCESSING

General

Food ingredient processing consists of Idaho Pacific Holdings, Inc., which was acquired by the Company on August 18, 2004. IPH, headquartered in Ririe, Idaho, manufactures and supplies dehydrated potato products to food manufacturers in the snack food, foodservice and bakery industries. IPH has three processing facilities located in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. Together these three facilities have the capacity to process approximately 114 million pounds of potatoes annually.

The Company derived 6%, 4% and 4% and of its consolidated operating revenues from the Food Ingredient Processing segment for each of the years ended December 31, 2007, 2006 and 2005, respectively. This segment's contribution to consolidated income from continuing operations for each of three years ended December 31, 2007, 2006 and 2005 was 8%, (8%) and 1%, respectively.

Customers

IPH sells to customers in the United States and internationally. Products are sold through company sales persons and broker sales representatives. Customers include end users in the food ingredient industries and distributors to the food ingredient industries and foodservice industries, both domestically and internationally.

Competition

The market for processed, dehydrated potato flakes, flour and granules is highly competitive. The ability to compete depends on superior product quality, competitive product pricing and strong customer relationships. IPH competes with numerous manufacturers and dehydrators of varying sizes in the United States, including companies with greater financial resources.

Potato Supply

The principal raw material used by IPH is washed process-grade potatoes from fresh packing operations and growers. These potatoes are unsuitable for use in other markets due to imperfections. They do not meet United States Department of Agriculture's general requirements and expectations for size, shape or color. While IPH has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key growers and other factors. A loss of raw materials or the necessity of paying much higher prices for raw materials could adversely affect the financial performance of IPH.

Backlog

IPH has backlog in place for 2008 of approximately 51.5 million pounds compared with 52.8 million pounds one year ago.

Regulations

IPH is regulated by the United States Department of Agriculture and the Federal Food and Drug Administration and other federal, state, local and foreign governmental agencies relating to the quality of products, sanitation, safety and environmental control. IPH adheres to strict manufacturing practices that dictate sanitary conditions conducive to a high quality food product. All facilities use wastewater systems that are regulated by government environmental agencies in their respective locations and are subject to permitting by these agencies. IPH believes that it complies with applicable laws and regulations in all material respects, and that continued compliance with such laws and regulations will not have a material effect on its capital expenditures, earnings or competitive position.

Capital Expenditures

Capital expenditures in the Food Ingredient Processing segment typically include additional investments in new dehydration equipment or expenditures to replace worn-out equipment. Capital expenditures may also be made for the purchase of land and buildings for plant expansion and for investments in management information systems. During 2007, no significant capital expenditures were made in the Food Ingredient Processing segment. Total capital expenditures for the Food Ingredient Processing segment during the five-year period 2008-2012 are estimated to be approximately $18 million.

Employees

At December 31, 2007 the Food Ingredient Processing segment had approximately 413 full-time employees.

OTHER BUSINESS OPERATIONS

General

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries; fiber optic and electric distribution systems; wastewater, and HVAC systems construction; transportation and energy services.

The Company derived 15%, 13% and 10% of its consolidated operating revenues from the Other Business Operations segment for each of the years ended December 31, 2007, 2006 and 2005, respectively. This segment's contribution to consolidated income from continuing operations for each of the three years ended December 31, 2007, 2006 and 2005 was 8%, 10% and (1%), respectively. Following is a brief description of the businesses included in this segment.

Foley Company, headquartered in Kansas City, Missouri, provides mechanical and prime contracting services for water and wastewater treatment plants, power generation plants, hospital and pharmaceutical facilities, and other industrial and manufacturing projects across a multi-state service area in the Central United States.

Midwest Construction Services, Inc. (MCS), located in Moorhead, Minnesota, is a holding company for five subsidiaries that provide a full spectrum of electrical design and construction services for the industrial, commercial and municipal business markets, including government, institutional, communications and utility and renewable energy.

Otter Tail Energy Services Company, headquartered in Fergus Falls, Minnesota, provides technical and engineering services and energy efficient lighting primarily in North Dakota and Minnesota.

E. W. Wylie Corporation (Wylie), located in West Fargo, North Dakota, is a flatbed, specialized contract and common carrier operating a fleet of tractors and trailers in 48 states and six Canadian provinces. Wylie has trucking terminals in West Fargo, North Dakota; Des Moines, Iowa; Fort Worth, Texas; Denver, Colorado; and Albertville, Minnesota.

Competition

Each of the businesses in Other Business Operations is subject to competition, as well as the effects of general economic conditions in their respective industries. The construction companies in this segment must compete with other construction companies in the Upper Midwest and the Central regions of the United States, including companies with greater financial resources, when bidding on new projects. The Company believes the principal competitive factors in the construction segment are price, quality of work and customer services.

The trucking industry, in which Wylie competes, is highly competitive. Wylie competes primarily with other short- to medium-haul, flatbed truckload carriers, internal shipping conducted by existing and potential customers and, to a lesser extent, railroads. Wylie recently entered the market of more specialized heavy haul trucks and trailers capable of hauling wind tower sections. Competition for the freight transported by Wylie is based primarily on service and efficiency and to a lesser degree, on freight rates. There are other trucking companies that have greater financial resources, operate more equipment or carry a larger volume of freight than Wylie and these companies compete with Wylie for qualified drivers.

Backlog

The construction companies in the Other Business Operations segment have backlog in place of approximately $77 million for 2008 compared with $74 million for the same period one year ago.

Capital Expenditures

Capital expenditures in this segment typically include investments in additional trucks, flatbed trailers and construction equipment. During 2007, capital expenditures of approximately $6 million were made in Other Business Operations. Capital expenditures during the five-year period 2008-2012 are estimated to be approximately $9 million for Other Business Operations. Operating leases are also used to finance the acquisition of trucks used by Wylie. Current operating lease commitments during the five-year period 2008-2012 are estimated to be $8 million.

Employees

At December 31, 2007 there were approximately 701 full-time employees in Other Business Operations. Moorhead Electric, Inc., a subsidiary of MCS, has 86 employees represented by local unions of the International Brotherhood of Electrical Workers and covered by a labor contract that expires on May 31, 2008. Foley Company has 189 employees represented by various unions, including Boilermakers, Carpenters and Millwrights, Cement Masons, Operating Engineers, Pipe Fitters and Plumbers and Teamsters. Foley Company has several labor contracts with various expiration dates in 2008 and 2009. Moorhead Electric, Inc. and Foley Company have not experienced any strike, work stoppage or strike vote, and consider their present relations with employees to be good.

Forward-Looking Information — Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the Act). When used in this Form 10-K and in future filings by the Company with the Securities and Exchange Commission, in the Company's press releases and in oral statements, words such as “may,” “will,” “expect,” “anticipate,” “continue,” “estimate,” “project,” “believes” or similar expressions are intended to identify forward-looking statements within the meaning of the Act. Such statements are based on current expectations and assumptions, and entail various risks and uncertainties that could cause actual results to differ materially from those expressed in such forward- looking statements.

The following factors, among others, could cause actual results for the Company to differ materially from those discussed in the forward-looking statements:

- Federal and state environmental regulation could require the Company to incur substantial capital expenditures and increased operating costs.
- Volatile financial markets and changes in the Company’s debt ratings could restrict the Company’s ability to access capital and could increase borrowing costs and pension plan expenses.
- The Company’s plans to grow and diversify through acquisitions may not be successful and could result in poor financial performance.
- The Company’s ability to grow its nonelectric businesses could be limited by state law.
- The Company is subject to federal and state legislation, regulations and actions that may have a negative impact on its business and results of operations.
- Competition is a factor in all of the Company’s businesses.
- Economic uncertainty could have a negative impact on the Company’s future revenues and earnings.
- Weather conditions or changes in weather patterns can adversely affect the Company’s operations and revenues.
- Actions by the regulators of the Company’s Electric segment could result in rate reductions, lower revenues or delays in recovering capital expenditures.
- The Company may not be able to respond effectively to deregulation initiatives in the electric industry, which could result in reduced revenues and earnings.
- The Company’s electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.
- Future operating results of the Company’s Electric segment will be impacted by the outcome of a rate case filed in Minnesota on October 1, 2007 requesting a final overall increase in Minnesota retail electric rates of 6.7%. The filing included a request for an interim rate increase of 5.4%, which went into effect on November 30, 2007. Interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the Utility’s request, which is expected by August 1, 2008. If final rates are lower than interim rates, the Utility will refund Minnesota customers the difference with interest.
- Certain costs currently included in the FCA in retail rates may be excluded from recovery through the FCA but may be subject to recovery through rates established in a general rate case. Further, all, or portions of, gross margins on asset-based wholesale electric sales may become subject to refund through the FCA as a result of a general rate case.
- Electric wholesale margins could be further reduced as the MISO market becomes more efficient.
- Electric wholesale trading margins could be reduced or eliminated by losses due to trading activities.
- Wholesale sales of electricity from excess generation could be affected by reductions in coal shipments to the Big Stone and Hoot Lake plants due to supply constraints or rail transportation problems beyond the Utility’s control.
- The Utility has capitalized $8.2 million in costs related to the planned construction of a second electric generating unit at its Big Stone Plant site as of December 31, 2007. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

- Existing or new laws or regulations addressing climate change or reductions of greenhouse gas emissions by federal or state authorities, such as mandated levels of renewable generation or mandatory reductions in CO_2 emission levels or taxes on CO_2 emissions, that result in increases in electric service costs could negatively impact the Company's net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the Utility provides service or through increased market prices for electricity.
- The Company's Plastics segment is highly dependent on a limited number of vendors for PVC resin, many of which are located in the Gulf Coast region, and a limited supply of resin. The loss of a key vendor or an interruption or delay in the supply of PVC resin could result in reduced sales or increased costs for this business.
- Reductions in PVC resin prices could negatively impact PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.
- The price and availability of raw materials could affect the revenues and earnings of the Company's Manufacturing segment.
- The Company's Food Ingredient Processing segment operates in a highly competitive market and is dependent on adequate sources of raw materials for processing. Should the supply of these raw materials be affected by poor growing conditions, this could negatively impact the results of operations for this segment.
- The Company's Food Ingredient Processing and wind tower manufacturing businesses could be adversely affected by changes in foreign currency exchange rates.
- Changes in the rates or methods of third-party reimbursements for diagnostic imaging services could result in reduced demand for those services or create downward pricing pressure, which would decrease revenues and earnings for the Company's Health Services segment.
- The Company's Health Services segment may not be able to retain or comply with the dealership arrangement and other agreements with Philips Medical.
- Actions by regulators of the Company's Health Services segment could result in monetary penalties or restrictions in the Company's health services operations.
- A significant failure or an inability to properly bid or perform on projects by the Company's construction businesses could lead to adverse financial results.

A further discussion of risk factors and cautionary statements is set forth under "Risk Factors and Cautionary Statements" and "Critical Accounting Policies Involving Significant Estimates" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" on pages 28 through 34 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto. These factors are in addition to any other cautionary statements, written or oral, which may be made or referred to in connection with any forward-looking statement or contained in any subsequent filings by the Company with the Securities and Exchange Commission. The Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise.

Item 1A. RISK FACTORS

The information required by this Item is incorporated by reference to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors and Cautionary Statements" on Pages 28 through 32 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 2. PROPERTIES

The Coyote Station, which commenced operation in 1981, is a 414,000 kW (nameplate rating) mine-mouth plant located in the lignite coal fields near Beulah, North Dakota and is jointly owned by the Utility, Northern Municipal Power Agency, Montana-Dakota Utilities Co. and Northwestern Public Service Company. The Utility is the operating agent of the Coyote Station and owns 35% of the plant.

The Utility, jointly with Northwestern Public Service Company and Montana-Dakota Utilities Co., owns the 414,000 kW (nameplate rating) Big Stone Plant in northeastern South Dakota which commenced operation in 1975. The Utility is the operating agent of Big Stone Plant and owns 53.9% of the plant.

Located near Fergus Falls, Minnesota, the Hoot Lake Plant is comprised of three separate generating units with a combined nameplate rating of 127,000 kW. The oldest Hoot Lake Plant generating unit was constructed in 1948 (7,500 kW nameplate rating) and was retired on December 31, 2005. A second unit was added in 1959 (53,500 kW nameplate rating) and a third unit was added in 1964 (66,000 kW nameplate rating) and modified in 1988 to provide cycling capability, allowing this unit to be more efficiently brought online from a standby mode.

As of December 31, 2007 the Utility's transmission facilities, which are interconnected with lines of other public utilities, consisted of 48 miles of 345 kV lines; 405 miles of 230 kV lines; 799 miles of 115 kV lines; and 4,039 miles of lower voltage lines, principally 41.6 kV. The Utility owns the uprated portion of the 48 miles of the 345 kV line, with Minnkota Power Cooperative retaining title to the original 230 kV construction.

In addition to the properties mentioned above, the Company owns and has investments in offices, service buildings and wind generation turbines. The Company's subsidiaries own facilities and equipment used to manufacture PVC pipe, produce dehydrated potato products and perform metal stamping, fabricating and contract machining; construction equipment and tools; wind towers and other heavy metal fabricated products; thermoformed products; commercial and waterfront equipment; medical imaging equipment and a fleet of flatbed trucks and trailers.

Management of the Company believes the facilities and equipment described above are adequate for the Company's present businesses.

All of the common shares of the companies owned by Varistar are pledged to secure indebtedness of Varistar.

Item 3. LEGAL PROCEEDINGS

The Company is the subject of various pending or threatened legal actions and proceedings in the ordinary course of its business. Such matters are subject to many uncertainties and to outcomes that are not predictable with assurance. The Company records a liability in its consolidated financial statements for costs related to claims, including future legal costs, settlements and judgments, where it has assessed that a loss is probable and an amount can be reasonably estimated. The Company believes the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the three months ended December 31, 2007.

Item 4A. EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF FEBRUARY 28, 2008)

Set forth below is a summary of the principal occupations and business experience during the past five years of the executive officers as defined by rules of the Securities and Exchange Commission. Except as noted below, each of the executive officers has been employed by the Company for more than five years in an executive or management position either with the Company or its wholly-owned subsidiary, Varistar.

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE
John D. Erickson (49)	4/8/02	Present: President and Chief Executive Officer
George A. Koeck (55)	4/10/00	Present: Corporate Secretary and General Counsel
Lauris N. Molbert (50)	6/10/02	Present: Executive Vice President and Chief Operating Officer
Kevin G. Moug (48)	4/9/01	Present: Chief Financial Officer and Treasurer
Charles S. MacFarlane (43)	5/1/03	President, Otter Tail Power Company
	Prior to 5/1/03	Interim President, Otter Tail Power Company

With the exception of Charles S. MacFarlane, the term of office for each of the executive officers is one year and any executive officer elected may be removed by the vote of the Board of Directors at any time during the term. Mr. MacFarlane is not appointed by the Board of Directors. Mr. MacFarlane is a son of John MacFarlane, who is the Chairman of the Board of Directors. There are no other family relationships between any of the executive officers.

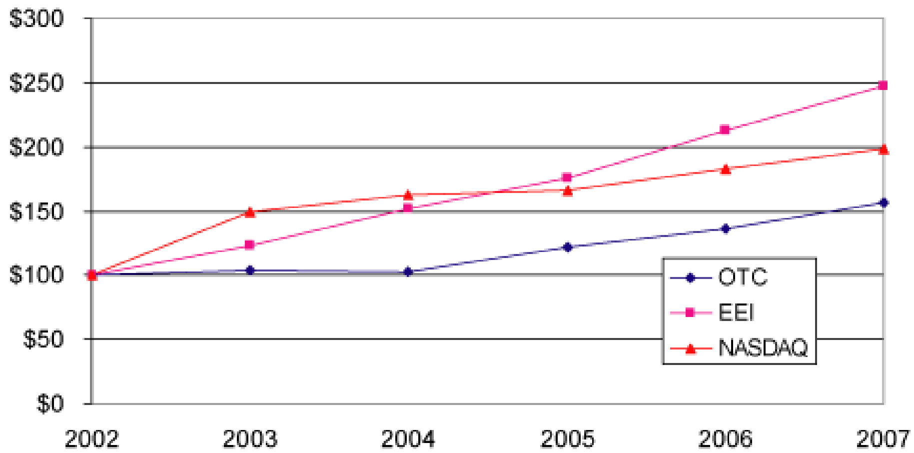
PART II

Item 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The information required by this Item is incorporated by reference to the first sentence under "Otter Tail Corporation Stock Listing" on Page 68, to "Selected Consolidated Financial Data" on Page 18, to "Retained Earnings Restriction" on Page 57 and to "Quarterly Information" on Page 65 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto. The Company did not repurchase any equity securities during the three months ended December 31, 2007.

PERFORMANCE GRAPH
COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

The graph below compares the cumulative total shareholder return on the Company's common shares for the last five fiscal years with the cumulative return of The NASDAQ Stock Market Index and the Edison Electric Institute Index (EEI) over the same period (assuming the investment of $100 in each vehicle on December 31, 2002, and reinvestment of all dividends).



	2002	2003	2004	2005	2006	2007
OTC	$100.00	$103.42	$103.02	$121.66	$136.04	$156.39
EEI	$100.00	$123.48	$151.68	$176.03	$212.56	$247.76
NASDAQ	$100.00	$149.52	$162.72	$166.18	$182.57	$197.98

Item 6. SELECTED FINANCIAL DATA

The information required by this Item is incorporated by reference to "Selected Consolidated Financial Data" on Page 18 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information required by this Item is incorporated by reference to "Management's Discussion and Analysis of Financial Condition and Results of Operations" on Pages 19 through 35 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this Item is incorporated by reference to "Quantitative and Qualitative Disclosures About Market Risk" on Pages 31and 32 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this Item is incorporated by reference to "Quarterly Information" on Page 65, the Company's audited financial statements on Pages 39 through 65 and "Report of Independent Registered Public Accounting Firm" on Page 36 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15 (e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2007, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2007.

There were no changes in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) during the fourth quarter ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

The annual report of the Company's management on internal control over financial reporting is incorporated by reference to "Management's Report Regarding Internal Controls Over Financial Reporting" on Page 36 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto. The attestation report of Deloitte & Touche LLP, the Company's independent registered public accounting firm, regarding the Company's internal control over financial reporting is incorporated by reference to "Report of Independent Registered Public Accounting Firm" on Page 36 of the Company's 2007 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item regarding Directors is incorporated by reference to the information under “Election of Directors” in the Company’s definitive Proxy Statement for the 2008 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 4A hereto. The information regarding Section 16 reporting is incorporated by reference to the information under “Security Ownership of Directors and Officers — Section 16(a) Beneficial Ownership Reporting Compliance” in the Company’s definitive Proxy Statement for the 2008 Annual Meeting. The information required by this Item regarding the Company’s procedures for recommending nominees to the Board of Directors is incorporated by reference to the information under “Meetings and Committees of the Board of Directors – Corporate Governance Committee” in the Company’s definitive Proxy Statement for the 2008 Annual Meeting. The information required by this Item in regards to the Audit Committee is incorporated by reference to the information under “Meetings and Committees of the Board of Directors – Audit Committee” in the Company’s definitive Proxy Statement for the 2008 Annual Meeting. The information regarding the Company’s Audit Committee financial experts is incorporated by reference to the information under “Meetings and Committees of the Board – Audit Committee” in the Company’s definitive Proxy Statement for the 2008 Annual Meeting.

The Company has adopted a code of conduct that applies to all of its directors, officers (including its principal executive officer, principal financial officer, and its principal accounting officer or controller or person performing similar functions) and employees. The Company’s code of conduct is available on its website at www.ottertail.com. The Company intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of conduct by posting such information on its website at the address specified above. Information on the Company’s website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

Item 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under “Compensation Discussion and Analysis,” “Report of Compensation Committee,” “Executive Compensation” and “Director Compensation” in the Company’s definitive Proxy Statement for the 2008 Annual Meeting.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item regarding security ownership is incorporated by reference to the information under “Outstanding Voting Shares” and “Security Ownership of Directors and Officers” in the Company’s definitive Proxy Statement for the 2008 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2007 about the Company's common stock that may be issued under all of its equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders			
1999 Stock Incentive Plan	1,128,755(1)	$17.94	1,202,173(2)
1999 Employee Stock Purchase Plan	—	N/A	397,156(3)
Equity compensation plans not approved by security holders	—	—	—
Total	1,128,755	$17.94	1,599,329

(1) Includes 109,000, 88,050 and 75,150 performance based share awards made in 2007, 2006 and 2005, respectively, 55,480 restricted stock units outstanding as of December 31, 2007, and 13,938 phantom shares as part of the deferred director compensation program and excludes 58,077 shares of restricted stock issued under the 1999 Stock Incentive Plan.

(2) The 1999 Stock Incentive Plan provides for the issuance of any shares available under the plan in the form of restricted stock, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights.

(3) Shares are issued based on employee's election to participate in the plan.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information under "Policy and Procedures Regarding Transactions with Related Persons" and "Election of Directors" in the Company's definitive Proxy Statement for the 2008 Annual Meeting.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information under "Ratification of Independent Registered Public Accounting Firm — Fees" and "Ratification of Independent Registered Public Accounting Firm – Pre-approval of Audit/Non-Audit Services Policy" in the Company's definitive Proxy Statement for the 2008 Annual Meeting.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) List of documents filed:

(1) and (2) See Table of Contents on Page 44 hereof.

(3) See Exhibit Index on Pages 45 through 52 hereof.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, copies of certain instruments defining the rights of holders of certain long-term debt of the Company are not filed, and in lieu thereof, the Company agrees to furnish copies thereof to the Securities and Exchange Commission upon request.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OTTER TAIL CORPORATION

By /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Treasurer

Dated: February 28, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature and Title

John D. Erickson President and Chief Executive Officer (principal executive officer) and Director	)	
Kevin G. Moug Chief Financial Officer and Treasurer (principal financial and accounting officer)	)	By /s/ John D. Erickson John D. Erickson Pro Se and Attorney-in-Fact Dated February 28, 2008
John C. MacFarlane Chairman of the Board and Director	)	
Karen M. Bohn, Director	)	
Dennis R. Emmen, Director	)	
Arvid R. Liebe, Director	)	
Edward J. McIntyre, Director	)	
Joyce Nelson Schuette, Director	)	
Nathan I. Partain, Director	)	
Gary J. Spies, Director	)	

OTTER TAIL CORPORATION

TABLE OF CONTENTS

FINANCIAL STATEMENTS, SUPPLEMENTARY FINANCIAL DATA, SUPPLEMENTAL
FINANCIAL SCHEDULES INCLUDED IN ANNUAL REPORT ON FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2007

The following items are incorporated in this Annual Report on Form 10-K by reference to the registrant's Annual Report to Shareholders for the year ended December 31, 2007 filed as an Exhibit hereto:

Schedules are omitted because of the absence of the conditions under which they are required, because the amounts are insignificant or because the information required is included in the financial statements or the notes thereto.

Exhibit Index
to
Annual Report
on Form 10-K
For Year Ended December 31, 2007

	Previously Filed		
	File No.	As Exhibit No.	
3-A	8-K filed 4/10/01	3	—Restated Articles of Incorporation, as amended (including resolutions creating outstanding series of Cumulative Preferred Shares).
3-B			—Restated Bylaws, as amended.
4-A-1	10-K for year ended 12/31/01	4-D-7	—Note Purchase Agreement, dated as of December 1, 2001.
4-A-2	10-K for year ended 12/31/02	4-D-4	—First Amendment, dated as of December 1, 2002, to Note Purchase Agreement, dated as of December 1, 2001.
4-A-3	10-Q for quarter ended 9/30/04	4.2	—Second Amendment, dated as of October 1, 2004, to Note Purchase Agreement, dated as of December 1, 2001.
4-A-4	8-K filed 12/20/07	4.2	—Third Amendment, dated as of December 1, 2007, to Note Purchase Agreement, dated as of December 1, 2001.
4-B	8-K filed 9/06/06	4.1	—Credit Agreement, dated as of September 1, 2006, between the Company, dba Otter Tail Power Company, and U.S. Bank National Association.
4-B-1	8-K filed 4/18/07	4.1	—First Amendment to Credit Agreement, dated as of April 13, 2007, to Credit Agreement, dated as of September 1, 2006.
4-B-2	8-K filed 9/06/07	4.1	—Second Amendment to Credit Agreement, dated as of August 31, 2007, to Credit Agreement, dated as of September 1, 2006.
4-C	8-K filed 2/28/07	4.1	—Note Purchase Agreement, dated as of February 23, 2007, between the Company and Cascade Investment L.L.C.
4-D	8-K filed 8/23/07	4.1	—Note Purchase Agreement, dated as of August 20, 2007.
4-D-1	8-K filed 12/20/07	4.3	—First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007.

	Previously Filed		
	File No.	As Exhibit No.	
4-E	8-K filed 10/5/07	4.1	—Credit Agreement, dated as of October 2, 2007, among Varistar Corporation, the Banks named therein, U.S. Bank National Association, a national banking association, as agent for the Banks and as Lead Arranger, and Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents.
4-E-1	8-K filed 12/7/07	4.1	—First Amendment to Credit Agreement, dated as of November 30, 2007, to Credit Agreement, dated as of October 2, 2007.
10-A	2-39794	4-C	—Integrated Transmission Agreement, dated August 25, 1967, between Cooperative Power Association and the Company.
10-A-1	10-K for year ended 12/31/92	10-A-1	—Amendment No. 1, dated as of September 6, 1979, to Integrated Transmission Agreement, dated as of August 25, 1967, between Cooperative Power Association and the Company.
10-A-2	10-K for year ended 12/31/92	10-A-2	—Amendment No. 2, dated as of November 19, 1986, to Integrated Transmission Agreement between Cooperative Power Association and the Company.
10-C-1	2-55813	5-E	—Contract dated July 1, 1958, between Central Power Electric Corporation, Inc., and the Company.
10-C-2	2-55813	5-E-1	—Supplement Seven dated November 21, 1973. (Supplements Nos. One through Six have been superseded and are no longer in effect.)
10-C-3	2-55813	5-E-2	—Amendment No. 1 dated December 19, 1973, to Supplement Seven.
10-C-4	10-K for year ended 12/31/91	10-C-4	—Amendment No. 2 dated June 17, 1986, to Supplement Seven.
10-C-5	10-K for year ended 12/31/92	10-C-5	—Amendment No. 3 dated June 18, 1992, to Supplement Seven.
10-C-6	10-K for year ended 12/31/93	10-C-6	—Amendment No. 4 dated January 18, 1994 to Supplement Seven.
10-D	2-55813	5-F	—Contract dated April 12, 1973, between the Bureau of Reclamation and the Company.
10-E-1	2-55813	5-G	—Contract dated January 8, 1973, between East River Electric Power Cooperative and the Company.

	Previously Filed		
	File No.	As Exhibit No.	
10-E-2	2-62815	5-E-1	—Supplement One dated February 20, 1978.
10-E-3	10-K for year ended 12/31/89	10-E-3	—Supplement Two dated June 10, 1983.
10-E-4	10-K for year ended 12/31/90	10-E-4	—Supplement Three dated June 6, 1985.
10-E-5	10-K for year ended 12/31/92	10-E-5	—Supplement No. Four, dated as of September 10, 1986.
10-E-6	10-K for year ended 12/31/92	10-E-6	—Supplement No. Five, dated as of January 7, 1993.
10-E-7	10-K for year ended 12/31/93	10-E-7	—Supplement No. Six, dated as of December 2, 1993
10-F	10-K for year ended 12/31/89	10-F	—Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970).
10-F-1	10-K for year ended 12/31/89	10-F-1	—Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-F-2	10-K for year ended 12/31/91	10-F-2	—Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-F-3	10-K for year ended 12/31/91	10-F-3	—Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).
10-F-4	10-K for year ended 12/31/91	10-F-4	—Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).
10-F-5	10-Q for quarter ended 9/30/03	10.1	—Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10-F-6	10-K for year ended 12/31/92	10-F-5	—Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant.
10-G	10-Q for quarter ended 06/30/04	10.3	—Master Coal Purchase and Sale Agreement by and between the Company, Montana-Dakota Utilities Co., Northwestern Corporation and Kennecott Coal Sales Company-Big Stone Plant (dated as of June 1, 2004).

	Previously Filed		
	File No.	As Exhibit No.	
10-H	2-61043	5-H	—Agreement for Sharing Ownership of Coyote Station Generating Unit No. 1 by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company and Minnesota Power & Light Company (dated as of July 1, 1977).
10-H-1	10-K for year ended 12/31/89	10-H-1	—Supplemental Agreement No. One, dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-2	10-K for year ended 12/31/89	10-H-2	—Supplemental Agreement No. Two, dated as of March 1, 1981, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1 and Amendment No. 2 dated March 1, 1981, to Coyote Plant Coal Agreement.
10-H-3	10-K for year ended 12/31/89	10-H-3	—Amendment, dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-4	10-K for year ended 12/31/92	10-H-4	—Agreement, dated as of September 5, 1985, containing Amendment No. 3 to Agreement for Sharing Ownership of Coyote Generating Unit No.1, dated as of July 1, 1977, and Amendment No. 5 to Coyote Plant Coal Agreement, dated as of January 1, 1978.
10-H-5	10-Q for quarter ended 9/30/01	10-A	—Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-6	10-Q for quarter ended 9/30/03	10.2	—Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-I	2-63744	5-I	—Coyote Plant Coal Agreement by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company, Minnesota Power & Light Company, and Knife River Coal Mining Company (dated as of January 1, 1978).
10-I-1	10-K for year ended 12/31/92	10-I-1	—Addendum, dated as of March 10, 1980, to Coyote Plant Coal Agreement.
10-I-2	10-K for year ended 12/31/92	10-I-2	—Amendment (No. 3), dated as of May 28, 1980, to Coyote Plant Coal Agreement.
10-I-3	10-K for year ended 12/31/92	10-I-3	—Fourth Amendment, dated as of August 19, 1985, to Coyote Plant Coal Agreement.
10-I-4	10-Q for quarter ended 6/30/93	19-A	—Sixth Amendment, dated as of February 17, 1993, to Coyote Plant Coal Agreement.

	Previously Filed		
	File No.	As Exhibit No.	
10-I-5	10-K for year ended 12/31/01	10-I-5	—Agreement and Consent to Assignment of the Coyote Plant Coal Agreement.
10-J-1	10-Q for quarter ended 06/30/05	10.1	—Big Stone II Power Plant Participation Agreement by and among the Company, Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency, as Owners (dated as of June 30, 2005).
10-J-1a	10-Q for quarter ended 6/30/06	10.6	—Amendment No. 1, dated as of June 1, 2006, to Participation Agreement (dated as of June 30, 2005).
10-J-1b	8-K filed 8/31/06	10.1	—Amendment No. 2, dated as of August 18, 2006, to Participation Agreement (dated as of June 30, 2005).
10-J-1c	8-K filed 10/11/06	10.1	—Amendment No. 3, effective September 1, 2006, to Participation Agreement (dated as of June 30, 2005).
10-J-1d	8-K filed 6/19/07	10.1	—Amendment No. 4, dated as of June 8, 2007, to Participation Agreement (dated as of June 30, 2005).
10-J-1e	8-K filed 9/12/07	10.1	—Amendment No. 5, dated as of September 1, 2007, to Participation Agreement (dated as of June 30, 2005).
10-J-1f	8-K filed 9/24/07	10.1	—Amendment No. 6, dated as of September 20, 2007, to Participation Agreement (dated as of June 30, 2005).
10-J-2	10-Q for quarter ended 06/30/05	10.2	—Big Stone II Power Plant Operation & Maintenance Services Agreement by and among the Company, Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency, as Owners, and the Company, as Operator (dated as of June 30, 2005).
10-J-3	10-Q for quarter ended 06/30/05	10.3	—Big Stone I and Big Stone II 2005 Joint Facilities Agreement by and among the Company, Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation dba NorthWestern Energy, Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency, as Owners (dated as of June 30, 2005).

	Previously Filed		
	File No.	As Exhibit No.	
10-J-3a	8-K filed 8/25/06	10.1	—Amendment No. 1, dated as of July 13, 2006, to Joint Facilities Agreement (dated as of June 30, 2005).
10-K-1	10-Q for quarter ended 9/30/99	10	—Power Sales Agreement between the Company and Manitoba Hydro Electric Board (dated as of July 1, 1999).
10-L	10-K for year ended 12/31/91	10-L	—Integrated Transmission Agreement by and between the Company, Missouri Basin Municipal Power Agency and Western Minnesota Municipal Power Agency (dated as of March 31, 1986).
10-L-1	10-K for year ended 12/31/88	10-L-1	—Amendment No. 1, dated as of December 28, 1988, to Integrated Transmission Agreement (dated as of March 31, 1986).
10-M	10-Q for quarter ended 06/30/04	10.1	—Master Coal Purchase Agreement by and between the Company and Kennecott Coal Sales Company — Hoot Lake Plant (dated as of December 31, 2001).
10-N-1	10-K for year ended 12/31/02	10-N-1	—Deferred Compensation Plan for Directors, as amended*
10-N-2	8-K filed 02/04/05	10.1	—Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-2a	10-K for year ended 12/31/06	10-N-2a	—First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-3	10-K for year ended 12/31/93	10-N-5	—Nonqualified Profit Sharing Plan.*
10-N-4	10-Q for quarter ended 3/31/02	10-B	—Nonqualified Retirement Savings Plan, as amended.*
10-N-5	8-K filed 4/13/06	10.3	—1999 Employee Stock Purchase Plan, As Amended (2006).
10-N-6	8-K filed 4/13/06	10.4	—1999 Stock Incentive Plan, As Amended (2006).
10-N-7	10-K for year ended 12/31/05	10-N-7	—Form of Stock Option Agreement*
10-N-8	10-K for year ended 12/31/05	10-N-8	—Form of Restricted Stock Agreement*
10-N-9	8-K filed 4/13/06	10.2	—Form of 2006 Performance Award Agreement.*

	Previously Filed		
	File No.	As Exhibit No.	
10-N-10	8-K filed 04/15/05	10.2	—Executive Annual Incentive Plan (Effective April 1, 2005).*
10-N-11	10-Q for quarter ended 6/30/06	10.5	—Form of 2006 Restricted Stock Unit Award Agreement.*
10-N-12	8-K filed 4/13/06	10.1	—Form of Restricted Stock Award Agreement for Directors.
10-O-1	10-Q for quarter ended 6/30/02	10-A	—Executive Employment Agreement, John Erickson.*
10-O-2	10-Q for quarter ended 6/30/02	10-B	—Executive Employment Agreement and amendment no. 1, Lauris Molbert.*
10-O-3	10-Q for quarter ended 6/30/02	10-C	—Executive Employment Agreement, Kevin Moug.*
10-O-4	10-Q for quarter ended 6/30/02	10-D	—Executive Employment Agreement, George Koeck.*
10-P-1	8-K filed 11/2/07	10.1	—Change in Control Severance Agreement, John Erickson.*
10-P-2	8-K filed 11/2/07	10.2	—Change in Control Severance Agreement, Lauris Molbert.*
10-P-3	8-K filed 11/2/07	10.3	—Change in Control Severance Agreement, Kevin Moug.*
10-P-4	8-K filed 11/2/07	10.4	—Change in Control Severance Agreement, George Koeck.*
13-A			—Portions of 2007 Annual Report to Shareholders incorporated by reference in this Form 10-K.
21-A			—Subsidiaries of Registrant.
23-A			—Consent of Deloitte & Touche LLP.
24-A			—Powers of Attorney.
31.1			—Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

	Previously Filed		
	File No.	As Exhibit No.	
31.2			—Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			—Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2			—Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Management contract of compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K.

(Back To Top)

Section 2: EX-3.B (RESTATED BYLAWS, AS AMENDED)

RESTATED BYLAWS
OF
OTTER TAIL CORPORATION
(As Amended Through November 26, 2007)

ARTICLE I.
OFFICES, CORPORATE SEAL

Section 1.01. Offices. The registered office of the corporation in Minnesota and the principal executive office shall be at 215 South Cascade Street, Fergus Falls, Minnesota 56537. The corporation may have such other offices, within or without the State of Minnesota, as the directors shall, from time to time, determine.

Section 1.02. Corporate Seal. The corporate seal shall be circular in form and shall have inscribed thereon the name of the corporation and the word “Minnesota” and the words “Corporate Seal.”

ARTICLE II.
MEETINGS OF SHAREHOLDERS

Section 2.01. Place of Meetings. Meetings of the shareholders shall be held at the principal executive office of the corporation or at such other place as may be designated by the directors, except that any meeting called by or at the demand of a shareholder shall be held in the county in which the principal executive office of the corporation is located.

Section 2.02. Regular Meetings. A regular meeting of the shareholders shall be held on an annual basis at 10:00 o’clock AM. on the second Monday of April in each year, or if that day shall fall on a holiday, then on the next succeeding business day, or on such other date and at such time as the Board of Directors shall by resolution establish. At the regular annual meeting the shareholders shall elect qualified successors for directors whose terms have expired or are due to expire at the time of the meeting and shall transact such other business as may properly come before them.

Section 2.03. Special Meetings. Special meetings of the shareholders may be held at any time and for any purpose or purposes and may be called by the Board of Directors, the chief executive officer or any other person specifically authorized under the Minnesota Business Corporation Act to call special meetings. Whenever voting power for the election of directors is vested in the holders of the Cumulative Preferred Shares or the Cumulative Preference Shares, the proper officers of the corporation shall, within twenty (20) days after written request therefor, signed by the holders of not less than five (5%) percent of the aggregate voting power (determined as provided in the Articles of Incorporation) vested in the Cumulative Preferred Shares or the Cumulative Preference Shares, as the case may be, of all series then outstanding, call a special meeting of shareholders for the purpose of electing directors. The date of such special meeting shall be not more than forty (40) days from the date of giving notice thereof. Whenever the holders of Cumulative Preferred Shares or the Cumulative Preference Shares shall be divested of voting powers with respect to the election of directors, the proper officers of the corporation shall within twenty (20) days after written request therefor, signed by the holders of not less than five (5%) percent of Common Shares outstanding, call a special meeting of the holders of Common Shares for the purpose of electing directors. The date of such special meeting shall be not more than forty (40) days from the date of giving notice thereof.

Section 2.04. Quorum; Adjourned Meetings. The holders of a majority of the Common Shares issued and outstanding, present in person or represented by proxy, shall be requisite to and constitute a quorum for the transaction of business except as otherwise provided by law, by the Articles of Incorporation or by these Bylaws. However, holders of a majority of the Common Shares who are present in person or by proxy shall have power to adjourn such meeting from time to time without notice other than announcement at the meeting.

At any meeting at which the holders of Cumulative Preferred Shares or Cumulative Preference Shares are entitled to vote for the election of directors, the holders of a majority of the aggregate voting power (determined as provided in the Articles of Incorporation) vested in the then outstanding Cumulative Preferred Shares or Cumulative Preference Shares, as the case may be, of all series present in person or by proxy, shall be requisite to and shall constitute a quorum for the election by them of the directors whom they are entitled to elect. However, the holders of a majority of the aggregate voting power (determined as provided in the Articles of Incorporation) vested in the Cumulative Preferred Shares or Cumulative Preference Shares, as the case may be, of all series who are present in person or by proxy, shall have power to adjourn such meeting for the election of directors by the holders of such Shares from time to time, without notice other than announcement at the meeting.

Section 2.05. Voting. At each meeting of the shareholders, every shareholder having the right to vote shall be entitled to vote either in person or by proxy. Each shareholder shall have such voting rights as are fixed by the Articles of Incorporation. Jointly owned shares may be voted by any joint owner unless the corporation receives written notice from any one of them denying the authority of that person to vote the shares. Upon the demand of any shareholder, the vote upon any question before the meeting shall be by ballot.

Section 2.06. Closing of Books. The Board of Directors may fix a date not more than 60 days preceding the date of any meeting of shareholders, as the date (the “record date”) for the determination of the shareholders entitled to notice of, and to vote at, such meeting. When a record date is so fixed, only shareholders as of that date are entitled to notice of and permitted to vote at that meeting of shareholders.

Section 2.07. Notice of Meetings. Notice of each regular meeting of shareholders, stating the date, time and place of the meeting, shall be given by mail to all shareholders entitled to vote thereat, not less than fifteen (15) days prior to said meeting. When voting power for the election of directors shall be vested in the holders of Cumulative Preferred Shares or Cumulative Preference Shares, such notice shall describe with particularity the voting rights of the holders of each series of such shares.

Notice of a special meeting of shareholders, stating the purpose of the meeting, shall be given by mail to all shareholders entitled to vote thereat, not less than one (1) week prior to said meeting. However, in the case of a special meeting of shareholders for the election of directors held when voting power for the election of directors shall be vested in the holders of Cumulative Preferred Shares or Cumulative Preference Shares, notice thereof shall be given by mail to all holders of Cumulative Preferred Shares or Cumulative Preference Shares, as the case may be, not less than fifteen (15) days prior to said meeting, and such notice shall describe with particularity the voting rights of the holders of each series of such shares.

Section 2.08. Waiver of Notice. Notice of any regular or special meeting may be waived by any shareholder either before, at or after such meeting orally or in a writing signed by such shareholder or a representative entitled to vote the shares of such shareholder. Attendance by a shareholder at any meeting of shareholders is a waiver of notice of such meeting, except where the shareholder objects at the beginning of the meeting to the transaction of business because the meeting is not lawfully called or convened or the item may not lawfully be considered at that meeting and the shareholder does not participate in the consideration of the item at that meeting.

Section 2.09. Nomination of Directors. Only persons nominated in accordance with the following procedures shall be eligible for election by shareholders as directors. Nominations of persons for election as directors at a meeting of shareholders called for the purpose of electing directors may be made (a) by or at the direction of the Board of Directors or (b) by any shareholder in the manner herein provided. For a nomination to be properly made by a shareholder, the shareholder must give written notice to the Secretary of the corporation so as to be received at the principal executive offices of the corporation at least 90 days before the date that is one year after the prior year's regular meeting. Each such notice shall set forth: (i) the name and address of the shareholder who intends to make the nomination and of the person or persons to be nominated; (ii) a representation that the shareholder is a holder of record of shares of the corporation entitled to vote at such meeting and intends to appear in person or by proxy at the meeting to nominate the person or persons specified in the notice; (iii) a description of all arrangements or understanding between the shareholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the shareholder; (iv) such other information regarding each nominee proposed by such shareholder as would have been required to be included in a proxy statement filed pursuant to the proxy rules of the Securities and Exchange Commission had each nominee been nominated, or intended to be nominated, by the Board of Directors; and (v) the consent of each nominee to serve as a director of the corporation if so elected. If the officer of the corporation presiding at a regular meeting of the shareholders determines that a director nomination was not made in accordance with the foregoing procedures, such nomination shall be void and shall be disregarded for all purposes.

Section 2.10. Shareholder Proposals. To be properly brought before a regular meeting of shareholders, business must be (a) specified in the notice of the meeting; (b) directed to be brought before the meeting by the Board of Directors; or (c) proposed at the meeting by a shareholder who (i) was a shareholder of record at the time of giving of notice provided for in these Bylaws; (ii) is entitled to vote at the meeting; and (iii) gives prior notice of the matter, which must otherwise be a proper matter for shareholder action, in the manner herein provided. For business to be properly brought before a regular meeting by a shareholder, the shareholder must give written notice to the Secretary of the corporation so as to be received at the principal executive offices of the corporation at least 90 days before the date that is one year after the prior year's regular meeting. Such notice shall set forth: (a) the name and record address of the shareholder and of the beneficial owner, if any, on whose behalf the proposal will be made; (b) the class and number of shares of the corporation owned by the shareholder and beneficially owned by the beneficial owner, if any, on whose behalf the proposal will be made; (c) a brief description of the business desired to be brought before the regular meeting and the reasons for conducting such business; and (d) any material interest in such business of the shareholder and the beneficial owner, if any, on whose behalf the proposal is made. The Chairman of the meeting may refuse to acknowledge any proposed business not made in compliance with the foregoing procedure. Notwithstanding anything in these Bylaws to the contrary, no business shall be considered properly brought before a regular meeting by a shareholder unless it is brought in accordance with the procedures set forth in this Section 2.10.

ARTICLE III.
DIRECTORS

Section 3.01. General Powers. The business and affairs of the corporation shall be managed by or under the direction of the Board of Directors.

Section 3.02. Number; Qualification; Term of Office; Manner of Election. Except at such times as the holders of Cumulative Preferred Shares and/or Cumulative Preference Shares shall have voting rights for the election of directors:

(i) The Board of Directors shall consist of such number of persons, not less than seven (7) nor more than nine (9), as may be determined by the shareholders from time to time at annual meetings thereof (subject to the authority of the Board of Directors to increase or decrease the number of directors as permitted by law).

(ii) The term of office of each director other than directors elected to fill vacancies shall be for the period ending at the third annual meeting following his election and until his successor is elected and qualified.

(iii) Vacancies in the Board of Directors occurring by reason of death, resignation, removal or disqualification shall be filled for the unexpired term of the director with respect to whom the vacancy occurred by a majority of the remaining directors of the Board of Directors, although less than a quorum.

(iv) Vacancies in the Board of Directors occurring by reason of newly created directorships resulting from an increase in the authorized number of directors by action of the Board of Directors as permitted by the Articles of Incorporation and the Bylaws of the corporation shall be filled by a majority vote of the directors serving at the time of such increase, each director so elected to a newly created directorship to serve for the appropriate term so as to maintain, as near as may be, an equal division between the classes of directors.

If at any time the holders of Cumulative Preferred Shares and/or Cumulative Preference Shares of the Company shall, under the provisions of paragraph (1) of subdivision B of Division IV or of paragraph (1) of subdivision C of Division IV of Article VI of the Articles of Incorporation, as amended, become entitled to elect any directors, then the terms of all incumbent directors shall expire at the time of the first annual meeting thereafter at which such holders of Cumulative Preferred Shares and/or Cumulative Preference Shares are so entitled to elect directors. If at any time the holders of Cumulative Preferred Shares of the Company shall, under the provisions of paragraph (2) of subdivision B of Division IV of Article VI of the Articles of Incorporation, as amended, become entitled to elect a majority of the Board of Directors, the terms of all incumbent directors shall expire whenever such majority has been duly elected and qualified. During any period during which the holders of Cumulative Preferred Shares and/or Cumulative Preference Shares of the corporation shall have voting rights with respect to directors under the provisions of Division IV of Article VI of the Articles of Incorporation, as amended, the Board of Directors shall consist of eleven (11) persons and the entire number of persons composing such Board shall be elected at each annual or special meeting of shareholders for the election of directors and shall serve until the next such annual or special meeting or until their successors have been elected and qualified; provided, however, that whenever the holders of Cumulative Preferred Shares and/or Cumulative Preference Shares acquire voting rights under paragraph (1) of subdivision B of Division IV or under paragraph (1) of subdivision C of Division IV of Article VI of the Articles of Incorporation, as amended, and exercise such rights at a special meeting called therefor, the terms of office of directors theretofore elected by the holders of Common Shares will not expire until the next annual meeting. If a vacancy or vacancies in the Board of Directors shall exist with respect to a director or directors who shall have been elected by the holders of either Cumulative Preferred Shares or Cumulative Preference Shares, the remaining directors elected by the holders of Cumulative Preferred Shares or Cumulative Preference Shares, as the case may be, by affirmative vote of a majority thereof, or the remaining director so elected if there be but one, may elect a successor or successors to hold office for the unexpired term of the director or directors whose place or places shall be vacant. Likewise, if a vacancy or vacancies shall exist with respect to a director or directors who shall have been elected by the holders of Common Shares, the remaining directors elected by the holders of Common Shares, by affirmative vote of a majority thereof, or the remaining director so elected if there be but one, may elect a successor or successors to hold office for the unexpired term of the director or directors whose place or places shall be vacant.

Whenever the Cumulative Preferred Shares shall be divested of voting powers with respect to the election of directors, the terms of all incumbent directors, other than directors elected by the holders of Cumulative Preference Shares, shall expire upon the election of their successors by the holders of the Common Shares at the next annual or special meeting of shareholders for the election of directors. Whenever the Cumulative Preference Shares shall be divested of voting powers with respect to the election of directors, the terms of all incumbent directors, other than directors elected by the holders of Cumulative Preferred Shares, shall expire on the election of their successors by the holders of the Common Shares at the next annual or special meeting of shareholders for the election of directors.

Directors of the corporation need not be shareholders.

Section 3.03. Board Meetings; Calling Meetings; Notice. The directors shall meet annually immediately after the election of directors, or as soon thereafter as is practicable, at the place at which the annual meeting of the shareholders was held, or at such other time and place as may be fixed by resolution adopted by the Board of Directors. Regular meetings of the Board of Directors shall be held from time to time at such time and place as may be from time to time fixed by resolution adopted by the Board of Directors. No notice need be given of any regular meeting. Special meetings of the Board of Directors shall be held in the office of the corporation in Fergus Falls, Minnesota, or at such other place as may from time to time be fixed by resolution adopted by the Board of Directors or as may be fixed by a waiver of notice of such meeting given by all of the directors. Special meetings of the Board of Directors may be called by the chief executive officer or by any two (2) directors. Notice of such special meeting shall be given by the Secretary to each director at least twenty-four (24) hours before such meeting by mail, telegraph, telephone, or in person.

Section 3.04. Waiver of Notice. Notice of any meeting of the Board of Directors may be waived by any director either before, at, or after such meeting orally or in a writing signed by such director. A director, by his attendance at any meeting of the Board of Directors, shall be deemed to have waived notice of such meeting, except where the director objects at the beginning of the meeting to the transaction of business because the meeting is not lawfully called or convened and does not participate thereafter in the meeting.

Section 3.05. Quorum. A majority of the directors holding office immediately prior to a meeting of the Board of Directors shall constitute a quorum for the transaction of business at such meeting.

Section 3.06. Absent Directors. A director may give advance written consent or opposition to a proposal to be acted on at a meeting of the Board of Directors. If such director is not present at the meeting, consent or opposition to a proposal does not constitute presence for purposes of determining the existence of a quorum, but consent or opposition shall be counted as a vote in favor of or against the proposal and shall be entered in the minutes or other record of action at the meeting, if the proposal acted on at the meeting is substantially the same or has substantially the same effect as the proposal to which the director has consented or objected.

Section 3.07. Conference Communications. Any or all directors may participate in any meeting or conference of the Board of Directors, or of any duly constituted committee thereof, by any means of communication through which the directors may simultaneously hear each other during such meeting. For the purposes of establishing a quorum and taking any action, such directors participating pursuant to this Section 3.07 shall be deemed present in person at the meeting.

Section 3.08. Committees. A resolution approved by the affirmative vote of a majority of the Board of Directors may establish committees having the authority of the Board in the management of the business of the corporation to the extent provided in the resolution. A committee shall consist of one or more persons, who need not be directors, appointed by affirmative vote of a majority of the directors present. Committees are subject to the direction and control of, and vacancies in the membership thereof shall be filled by, the Board of Directors, except as provided by Section 3.09 and by Minnesota Statutes Section 302A.243. A majority of the members of the committee holding office immediately prior to a meeting of the committee shall constitute a quorum for the transaction of business, unless a larger or smaller proportion or number is provided in the resolution establishing the committee.

Section 3.09. Committee of Disinterested Persons. Pursuant to the procedure set forth in Section 3.08, the Board may establish a committee composed of two or more disinterested directors or other disinterested persons to determine whether it is in the best interests of the corporation to pursue a particular legal right or remedy of the corporation and whether to cause the dismissal or discontinuance of a particular proceeding that seeks to assert a right or remedy on behalf of the corporation. The committee, once established, is not subject to the direction or control of, or termination by, the Board. A vacancy on the committee may be filled by a majority of the remaining committee members. The good faith determinations of the committee are binding upon the corporation and its directors, officers and shareholders. The committee terminates when it issues a written report of its determination to the Board.

Section 3.10. Written Action. Any action which might be taken at a meeting of the Board of Directors, or any duly constituted committee thereof, may be taken without a meeting if done in writing and signed by all of the directors or committee members, unless the Articles provide otherwise and the action need not be approved by the Shareholders.

Section 3.11 . Compensation. The Board may fix the compensation, if any, of directors and members of any committee established by the Board.

Section 3.12. Removal. The affirmative vote of the holders of at least 75% of the outstanding Common Shares entitled to vote at an election of directors may remove from office at any time, with or without cause, any and all of the directors who shall have been elected by the holders of Common Shares. In the event that the Board of Directors or any one or more directors be so removed, new directors shall be elected at the same meeting. No provision of this Section 3.12 may be amended or repealed except by the affirmative vote of the holders of at least 75% of the outstanding Common Shares of the corporation unless the Board of Directors, if all such directors are Continuing Directors, as defined in Article VI of the Articles of Incorporation, shall unanimously recommend such amendment or repeal.

ARTICLE IV.
OFFICERS

Section 4.01. Number and Designation. The corporation shall have one or more natural persons exercising the functions of the offices of chief executive officer and chief financial officer. The Board of Directors may elect or appoint such other officers or agents as it deems necessary for the operation and management of the corporation, with such powers, rights, duties and responsibilities as may be determined by the Board, including, without limitation, a Chairman of the Board, a President, one or more Vice Presidents, a Controller, a Secretary, a Treasurer, and such assistant officers or other officers as may from time to time be elected or appointed by the Board. The Board shall elect the persons to serve as chief executive officer and chief financial officer and may elect such other officers at the annual meeting of the Board of Directors. Such officers so elected shall hold office until the next annual meeting of directors and until their successors are elected and qualify, subject to removal as provided in Section 4.11. Each such officer shall have the powers, rights, duties and responsibilities set forth in these Bylaws unless otherwise determined by the Board or, in the absence of such determination by the Board, as may be prescribed by the chief executive officer. Any number of offices may be held by the same person.

Section 4.02. Chief Executive Officer. Either the Chairman of the Board or the President of the corporation may be designated from time to time by the Board to be the chief executive officer of the corporation. Unless provided otherwise by a resolution adopted by the Board of Directors, the chief executive officer (a) shall have general active management of the business of the corporation; (b) shall, when present, preside at all meetings of the shareholders; (c) shall see that all orders and resolutions of the Board are carried into effect; (d) shall sign and deliver in the name of the corporation any deeds, mortgages, bonds, contracts or other instruments pertaining to the business of the corporation, except in cases in which the authority to sign and deliver is required by law to be exercised by another person or is expressly delegated by these Bylaws or the Board to some other officer or agent of the corporation; (e) may maintain records of and certify proceedings of the Board and shareholders; and (f) shall perform such other duties as may from time to time be assigned to him by the Board.

Section 4.03 Chief Financial Officer. Unless provided otherwise by a resolution adopted by the Board of Directors, the chief financial officer (a) shall keep accurate financial records for the corporation; (b) shall deposit all monies, drafts and checks in the name of and to the credit of the corporation in such banks and depositories as the Board of Directors shall designate from time to time; (c) shall endorse for deposit all notes, checks and drafts received by the corporation as ordered by the Board, making proper vouchers therefor; (d) shall disburse corporate funds and issue checks and drafts in the name of the corporation, as ordered by the Board; (e) shall render to the chief executive officer and the Board of Directors, whenever requested, an account of all of his transactions as chief financial officer and of the financial condition of the corporation; and (f) shall perform such other duties as may be prescribed by the Board of Directors or the chief executive officer from time to time.

Section 4.04. Chairman of the Board. The Chairman of the Board, if one is elected, shall preside at all meetings of the directors and shall have such other duties as may be prescribed, from time to time, by the Board of Directors.

Section 4.05. President. Unless otherwise determined by the Board, the President shall be the chief executive officer of the corporation and shall supervise and control the business affairs of the corporation. If an officer other than the President is designated chief executive officer, the President shall perform such duties as may from time to time be assigned to him by the Board.

Section 4.06. Vice President. The Board of Directors may designate one or more Vice Presidents, who shall have such designations and powers and shall perform such duties as prescribed by the Board of Directors or by the chief executive officer. In the event of the absence or disability of the President, Vice Presidents shall succeed to his power and duties in the order designated by the Board of Directors.

Section 4.07. Controller. The Controller shall be the chief accounting officer of the corporation. He shall maintain adequate records of all assets, liabilities and transactions of the corporation and see that adequate audits thereof are currently and regularly made; and, in conjunction with other officers and department heads, shall initiate and enforce procedures whereby the business of the corporation shall be conducted with maximum safety, efficiency and economy. He shall have such further powers and perform such other duties as may be prescribed by the Board of Directors or the chief executive officer.

Section 4.08. Secretary. The Secretary shall be secretary of and shall attend all meetings of the shareholders and Board of Directors and shall record all proceedings of such meetings in the minute book of the corporation. Except as otherwise required or permitted by statute or by these Bylaws, the Secretary shall give notice of meetings of shareholders and directors. The Secretary shall perform such other duties as may, from time to time, be prescribed by the Board of Directors or by the chief executive officer.

Section 4.09. Treasurer. Unless otherwise determined by the Board, the Treasurer shall be the chief financial officer of the corporation. If an officer other than the Treasurer is designated chief financial officer, the Treasurer shall perform such duties as may from time to time be assigned to him by the Board.

Section 4.10. Authority and Duties. In addition to the foregoing authority and duties, all officers of the corporation shall respectively have such authority and perform such duties in the management of the business of the corporation as may be determined from time to time by the Board of Directors. Unless prohibited by a resolution of the Board of Directors, an officer elected or appointed by the Board may, without specific approval of the Board, delegate some or all of the duties and powers of an office to other persons. An officer who delegates the duties or powers of an officer remains subject to the standard of conduct for an officer with respect to the discharge of all duties and powers so delegated. The officers of the corporation shall give such bonds to the corporation for the faithful performance of their duties as may be required from time to time by the Board of Directors.

Section 4.11. Removal and Vacancies. Any officer may be removed from his office by the affirmative vote of a majority of the Board of Directors present, at any time, with or without cause. Such removal, however, shall be without prejudice to the contract rights of the person so removed. If there be a vacancy among the officers of the corporation by reason of death, resignation or otherwise, such vacancy shall be filled for the unexpired term by the Board of Directors.

Section 4.12. Compensation. The officers of this corporation shall receive such compensation for their services as may be determined by or in accordance with resolutions of the Board of Directors.

ARTICLE V.
SHARES AND THEIR TRANSFER

Section 5.01. Certificates for Shares. The shares of the corporation may be either certificated shares or uncertificated shares or a combination thereof. A resolution approved by a majority of the directors on the Board of Directors may provide that some or all of any or all classes and series of the shares of the corporation will be uncertificated shares. Every owner of shares of the corporation shall be entitled to a certificate for such shares, to be in such form as shall be prescribed by law and adopted by the Board of Directors, certifying the number of shares of the corporation owned by such shareholder. The certificates for such shares shall be numbered in the order in which they shall be issued and shall be signed, in the name of the corporation, by the President or a Vice President and by the Secretary or an Assistant Secretary or by such officers as the Board of Directors may designate. If the certificate is signed by a transfer agent or registrar, such signatures of the corporate officers may be facsimiles, engraved or printed. Every certificate surrendered to the corporation or its transfer agent for exchange or transfer shall be canceled, and no new certificate or certificates shall be issued in exchange for any existing certificate until such existing certificate shall have been so canceled, except in cases provided for in Section 5.03.

Section 5.02. Transfer of Shares. Transfer of shares on the books of the corporation may be authorized only by the shareholder of record thereof, or the shareholder’s legal representative, who shall furnish proper evidence of authority to transfer, or the shareholder’s duly authorized attorney-in-fact, and, in the case of certificated shares, upon surrender of the certificate or the certificates for such shares to the corporation or its transfer agent duly endorsed. The corporation may treat as the absolute owner of shares of the corporation the person or persons in whose name shares are registered on the books of the corporation. The Board of Directors may appoint one or more transfer agents and registrars to maintain the share records of the corporation and to effect share transfers on its behalf.

Section 5.03. Loss of Certificates. Except as otherwise provided by Minnesota Statutes Section 302A.419, any shareholder claiming a certificate for shares to be lost, stolen or destroyed shall make an affidavit of that fact in such form as the Board of Directors shall require and shall, if the Board of Directors so requires, give the corporation a bond of indemnity in form, in an amount, and with one or more sureties satisfactory to the chief executive officer, the chief financial officer and the transfer agent and registrar, if any, to indemnify the corporation against any claim which may be made against it on account of the reissue of such certificate, whereupon a new certificate may be issued in the same tenor and for the same number of shares as the one alleged to have been lost, stolen or destroyed.

ARTICLE VI.
DIVIDENDS, RECORD DATE

Section 6.01. Dividends. The Board of Directors shall have the authority to declare dividends and other distributions upon shares to the extent permitted by law.

Section 6.02. Record Date. The Board of Directors may fix a date not exceeding 60 days preceding the date fixed for the payment of any dividend as the record date for the determination of the shareholders entitled to receive payment of the dividend and, in such case, only shareholders of record on the date so fixed shall be entitled to receive payment of such dividend.

ARTICLE VII.
SECURITLES OF OTHER CORPORATIONS

Section 7.01. Voting Securities Held by the Corporation. The chief executive officer shall have full power and authority on behalf of the corporation (a) to attend any meeting of security holders of other corporations in which the corporation may hold securities and to vote such securities on behalf of this corporation; (b) to execute any proxy for such meeting on behalf of the corporation; or (c) to execute a written action in lieu of a meeting of such other corporation on behalf of this corporation. At such meeting, the chief executive officer shall possess and may exercise any and all rights and powers incident to the ownership of such securities that the corporation possesses. The Board of Directors or the chief executive officer may, from time to time, confer or delegate such powers to one or more other persons.

Section 7.02. Purchase and Sale of Securities. The chief executive officer shall have full power and authority on behalf of the corporation to purchase, sell, transfer or encumber any and all securities of any other corporation owned by the corporation, and may execute and deliver such documents as may be necessary to effectuate such purchase, sale, transfer or encumbrance. The Board of Directors or the chief executive officer may, from time to time, confer or delegate such powers to one or more other persons.

ARTICLE VIII.
INDEMNIFICATION OF CERTAIN PERSONS

Section 8.01. The corporation shall indemnify such persons, for such expenses and liabilities, in such manner, under such circumstances, and to such extent as permitted by Minnesota Statutes Section 302A. 521, as now enacted or hereafter amended.

(Back To Top)

Section 3: EX-13.A (PORTIONS OF 2007 ANNUAL REPORT TO SHAREHOLDERS)

Selected Consolidated Financial Data

(thousands, except number of shareholders and per-share data)	2007	2006	2005	2004	2003
Revenues					
Electric	**$ 323,478**	$ 306,014	$ 312,985	$ 266,385	$267,494
Plastics	**149,012**	163,135	158,548	115,426	86,009
Manufacturing	**381,599**	311,811	244,311	201,615	157,401
Health Services	**130,670**	135,051	123,991	114,318	100,912
Food Ingredient Processing	**70,440**	45,084	38,501	14,023	—
Other Business Operations (1)	**185,730**	145,603	105,821	102,516	78,094
Corporate Revenues and Intersegment Eliminations (1)	**(2,042)**	(1,744)	(2,288)	(1,247)	(921)
Total Operating Revenues	**$1,238,887**	$1,104,954	$ 981,869	$ 813,036	$688,989
Net Income from Continuing Operations	**53,961**	50,750	53,902	40,502	38,297
Net Income from Discontinued Operations	**—**	362	8,649	1,693	1,359
Net Income	**53,961**	51,112	62,551	42,195	39,656
Operating Cash Flow from Continuing Operations	**84,812**	79,207	90,348	54,410	76,464
Operating Cash Flow — Continuing and Discontinued Operations	**84,812**	80,246	95,800	56,301	76,955
Capital Expenditures — Continuing Operations	**161,985**	69,448	59,969	49,484	48,783
Total Assets	**1,454,754**	1,258,650	1,181,496	1,134,148	986,423
Long-Term Debt	**342,694**	255,436	258,260	261,805	262,311
Redeemable Preferred	**—**	—	—	—	—
Basic Earnings Per Share — Continuing Operations (2)	**1.79**	1.70	1.82	1.53	1.47
Basic Earnings Per Share — Total (2)	**1.79**	1.71	2.12	1.59	1.52
Diluted Earnings Per Share — Continuing Operations (2)	**1.78**	1.69	1.81	1.52	1.46
Diluted Earnings Per Share — Total (2)	**1.78**	1.70	2.11	1.58	1.51
Return on Average Common Equity	**10.5%**	10.6%	13.9%	12.0%	12.2%
Dividends Per Common Share	**1.17**	1.15	1.12	1.10	1.08
Dividend Payout Ratio	**66%**	68%	53%	70%	72%
Common Shares Outstanding — Year End	**29,850**	29,522	29,401	28,977	25,724
Number of Common Shareholders (3)	**14,509**	14,692	14,801	14,889	14,723

Notes:

(1) *Beginning in 2007 corporate revenues and expenses are no longer reported as components of Other Business Operations. Prior years have been restated accordingly.*

(2) *Based on average number of shares outstanding.*

(3) *Holders of record at year end.*

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Otter Tail Corporation and our subsidiaries form a diverse group of businesses with operations classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. Our primary financial goals are to maximize earnings and cash flows and to allocate capital profitably toward growth opportunities that will increase shareholder value. Meeting these objectives enables us to preserve and enhance our financial capability by maintaining desired capitalization ratios and a strong interest coverage position and preserving solid credit ratings on outstanding securities, which, in the form of lower interest rates, benefits both our customers and shareholders.

Our strategy is straightforward: Reliable utility performance combined with growth opportunities at all our businesses provides long-term value. This includes growing our core electric utility business which provides a strong base of revenues, earnings and cash flows. In addition, we look to our nonelectric operating companies to provide organic growth as well. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. We expect much of our growth in the next few years will come from major capital investments at our existing companies. We adhere to strict guidelines when reviewing acquisition candidates. Our aim is to add companies that will produce an immediate positive impact on earnings and provide long-term growth potential. We believe that owning well-run, profitable companies across different industries will bring more growth opportunities and more balance to results. In doing this, we also avoid concentrating business risk within a single industry. All our operating companies operate under a decentralized business model with disciplined corporate oversight.

We assess the performance of our operating companies over time, using the following criteria:

- ability to provide returns on invested capital that exceed our weighted average cost of capital over the long term; and
- assessment of an operating company's business and potential for future earnings growth.

We are a committed long-term owner and therefore we do not acquire companies in pursuit of short-term gains. However, we will divest operating companies that do not meet these criteria over the long term.

The following major events occurred in our company in 2007:

- Our annual consolidated revenues topped $1.2 billion for the first time in our history.
- We reported record earnings in our manufacturing and food ingredient processing segments.
- Construction expenditures totaled $162 million, including expenditures for the electric utility's portion of the Langdon wind project and DMI Industries, Inc.'s new wind tower manufacturing facility near Tulsa, Oklahoma.
- We continued work with other regional utilities on the planning and permitting process for a nominally rated 500-580 megawatt coal-fired electric generating plant (Big Stone II) on the site of the existing Big Stone Plant.
- The electric utility filed a general rate case in Minnesota in October 2007. The last general rate case filing in Minnesota was in 1986.

Major growth strategies and initiatives in our company's future include:

- Planned capital budget expenditures of up to $899 million for the years 2008-2012 of which $759 million is for capital projects at the electric utility, including $336 million related to Big Stone II, $106 million for wind generation and associated transmission projects and $67 million for anticipated expansion of transmission capacity in Minnesota (CapX 2020). See "Capital Requirements" section for further discussion.
- Pursuing the regulatory approvals, financing and other arrangements necessary to build Big Stone II.

- Adding more renewable resources to our electric resource mix.
- Completion of the Minnesota general rate case and rate filings in North Dakota and South Dakota.
- The continued investigation and evaluation of organic growth and strategic acquisition opportunities.

The following table summarizes our consolidated results of operations for the years ended December 31:

(in thousands)	2007	2006
Operating Revenues:		
Electric	$ 323,158	$ 305,703
Nonelectric	915,729	799,251
Total Operating Revenues	$1,238,887	$1,104,954
Net Income from Continuing Operations:		
Electric	$ 24,498	$ 24,181
Nonelectric	29,463	26,569
	53,961	50,750
Net Income from Discontinued Operations	—	362
Total Net Income	$ 53,961	$ 51,112

The 12.1% increase in consolidated revenues in 2007 compared with 2006 reflects significant revenue growth from our manufacturing segment, construction companies and food ingredient processing segment. Revenues increased $69.8 million in our manufacturing segment in 2007 mainly due to increased sales of wind towers and waterfront products. Our construction companies' revenues grew by $40.2 million in 2007 as a result of increased construction activity. Food ingredient processing revenues increased $25.4 million as a result of a 29.5% increase in the volume of products sold combined with an increase in product prices. Revenues in the electric segment increased $17.5 million mainly due to an $8.4 million increase in fuel clause adjustment (FCA) revenues related to an increase in fuel and purchased power costs in 2007 and a 3.3% increase in retail megawatt-hour (mwh) sales in 2007. Revenues from our health services segment decreased $4.4 million in 2007, reflecting a shift from traditional dealership distribution of products in 2006 to more commission-based compensation for sales in 2007. Revenues decreased by $14.1 million in our plastics segment in 2007 as a result of lower pipe sales prices driven by a decline in polyvinyl chloride (PVC) resin prices.

Record net income from our manufacturing segment and an $8.5 million turnaround in net income at our food ingredient processing business more than offset decreases in net income from our plastics, other business operations and health services segments.

Following is a more detailed analysis of our operating results by business segment for the three years ended December 31, 2007, 2006 and 2005, followed by our outlook for 2008, a discussion of our financial position at the end of 2007 and risk factors that may affect our future operating results and financial position.

RESULTS OF OPERATIONS

This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes found elsewhere in this report. See note 2 to our consolidated financial statements for a complete description of our lines of business, locations of operations and principal products and services.

Amounts presented in the segment tables that follow for 2007, 2006 and 2005 operating revenues, cost of goods sold and other nonelectric operating expenses will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	2007	2006	2005
Operating Revenues:			
Electric	$ 320	$ 311	$ 361
Nonelectric	1,722	1,433	1,927
Cost of Goods Sold	1,539	1,433	2,070
Other Nonelectric Expenses	503	311	218

ELECTRIC

The following table summarizes the results of operations for our electric segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Retail Sales Revenues	$ 276,894	6	$ 260,926	5	$ 248,939
Wholesale Revenues	22,306	(13)	25,514	(39)	41,953
Net Marked-to-Market Gains	3,334	639	451	(90)	4,444
Other Revenues	20,944	10	19,123	8	17,649
Total Operating Revenues	$ 323,478	6	$ 306,014	(2)	$ 312,985
Production Fuel	60,482	3	58,729	5	55,927
Purchased Power — System Use	74,690	28	58,281	(1)	58,828
Other Operation and Maintenance Expenses	107,041	3	103,548	4	99,904
Depreciation and Amortization	26,097	1	25,756	6	24,397
Property Taxes	9,413	(2)	9,589	(5)	10,043
Operating Income	$ 45,755	(9)	$ 50,111	(22)	$ 63,886

2007 compared with 2006

The $16.0 million increase in retail electric sales revenues in 2007 compared with 2006 includes a net increase of $8.4 million in FCA revenues mainly related to an increase in purchased power costs in the fourth quarter of 2007 to replace generation lost during a scheduled major maintenance shutdown of our Big Stone Plant. The increase in retail revenues also includes $7.6 million related to a 3.3% increase in retail mwh sales. Residential mwh sales increased 4.0% due, in part, to a 9.6% increase in heating degree days. Increased oil and ethanol production in our electric service territory and surrounding regions contributed to a 3.1% increase in commercial and industrial mwh sales. The increase in FCA revenues related to increases in fuel and purchased power costs for system use between the years was $14.4 million. The $8.4 million net increase in FCA revenues includes the effects of $6.0 million in FCA adjustments and refunds in 2006 and 2007 that were not related to increases in fuel and purchased power costs between the years.

A 30.6% decline in wholesale mwh sales from company-owned generation in 2007 compared with 2006 resulted in a $2.8 million decrease in wholesale revenues despite a 26.7% increase in the price per mwh sold from company-owned generating units. In 2006, advance purchases of electricity in anticipation of normal winter weather resulted in increased wholesale electric sales in January 2006, when the weather was unseasonably mild. Advance purchases of electricity in anticipation of coal supply constraints at Big Stone and Hoot Lake plants in the second quarter of 2006 freed up more generation for wholesale sales when coal supplies improved in May 2006. Net revenues from energy trading activities, including net mark-to-market gains on forward energy contracts, were $5.3 million in 2007 compared with $2.8 million in 2006. The $2.5 million increase in revenue from energy trading activities reflects a $3.5 million increase in profits from purchased power resold and net settlements of forward energy contracts and a $2.9 million increase in net mark-to-market gains on forward energy contracts, offset by a $3.9 million decrease in profits related to the purchase and sale of financial transmission rights (FTRs).

The $1.8 million increase in other electric operating revenues in 2007 compared with 2006 is related to increases in revenues of $0.8 million from electric system planning and construction work performed for other companies, $0.5 million from integrated transmission agreements and $0.4 million for reimbursement of system operations costs from the Midwest Independent Transmission System Operator (MISO).

The $1.8 million increase in fuel costs in 2007 compared with 2006 reflects an 8.7% increase in the cost of fuel per mwh generated offset by a 5.3% decrease in mwhs generated. Generation used for wholesale electric sales decreased 30.6% while generation for retail sales decreased 0.8% between the years. Fuel costs for the electric utility’s combustion turbines increased $2.0 million due to an 86.1% increase in mwhs generated from those units. Fuel costs per mwh increased at all of the electric utility’s steam turbine generating units as a result of increases in coal and coal transportation costs between the years. Much of the increase in coal and coal transportation costs is related to higher diesel fuel prices. Over 90% of the fuel cost increases associated with generation to serve retail electric customers is subject to recovery through the FCA component of retail rates.

The $16.4 million increase in purchased power — system use (to serve retail customers) in 2007 compared with 2006 is due to a 22.1% increase in mwh purchases for system use combined with a 4.9% increase in the cost per mwh purchased. The increase in mwh purchases was a result of power purchased to replace generation lost during the scheduled major maintenance shutdown of our Big Stone Plant in the fourth quarter of 2007.

The $3.5 million increase in other operation and maintenance expenses for 2007 compared with 2006 includes increases of: (1) $1.1 million in labor and benefit costs related to wage and salary increases averaging approximately 3.8% and an increase in employee numbers between the periods, (2) $1.0 million in costs related to contracted construction work performed for other companies, (3) $0.7 million in external costs related to rate case preparation and (4) $0.6 million in tree-trimming expenditures.

2006 compared with 2005

The $12.0 million increase in retail electric sales revenues in 2006 compared with 2005 is due mainly to a $9.5 million increase in FCA revenues related to increases in fuel and purchased power costs for system use and to a $3.6 million increase in FCA revenue related to the 2006 reversal of a $1.9 million FCA refund provision recorded in December 2005. The refund provision is related to MISO costs subject to collection through the FCA in Minnesota. In December 2005, the Minnesota Public Utilities Commission (MPUC) issued an order denying recovery of certain MISO-related costs through the FCA and requiring a refund of amounts previously collected. In February 2006, the MPUC reconsidered its order and eliminated the refund requirement. In December 2006, the MPUC ordered the refund of $0.4 million in MISO schedule 16 and 17 administrative costs that had been collected through the FCA, allowing for deferred recovery of those costs in the electric utility's next general rate case which was filed on October 1, 2007. The FCA revenues also include $2.6 million in unrecovered fuel and purchased power costs under an FCA true-up mechanism established by order of the MPUC. The Minnesota FCA true-up relates to costs incurred from July 2004 through June 2006 that were recovered from Minnesota customers from August 2006 through July 2007. The electric utility currently is accruing for the Minnesota FCA true-up on a monthly basis along with its regular monthly FCA accrual.

Retail mwh sales increased 2.5% between the years as a result of increased sales to industrial customers mainly due to increased consumption by pipeline customers as higher oil prices led to an increase in the volume of product being transported from Canada and the Williston basin. A 9.8% decline in the price of wholesale mwh sales from company-owned generation in 2006 compared with 2005 resulted in a $1.7 million decrease in revenues despite a 3.4% increase in mwh sales from company-owned generating units. Advance purchases of electricity in anticipation of normal winter weather resulted in increased wholesale electric sales in January 2006 due to unseasonably mild weather. Wholesale sales from company-owned generation were curtailed in February and March 2006 as generation levels were restricted due to coal supply constraints at Big Stone and Hoot Lake plants. Advance purchases of electricity in anticipation of continuing coal supply constraints in the second quarter of 2006 supplemented increased generation when coal supplies improved in May, providing additional resources for wholesale sales.

Net revenue from energy trading activities, including net mark-to-market gains on forward energy contracts, were $2.8 million in 2006 compared with $21.6 million in 2005. The $18.8 million decrease in revenue from energy trading activities reflects an $11.4 million reduction in net profits from virtual transactions, a $4.5 million reduction in profits from purchased power resold and a $4.0 million decrease in net mark-to-market gains on forward energy contracts, offset by a $1.1 million increase in profits from investments in FTRs. With the inception of the MISO Day 2 markets in April 2005, the MISO introduced two new types of contracts, virtual transactions and FTRs. Virtual transactions are of two types: (1) a Virtual Demand Bid, which is a bid to purchase energy in the MISO's Day-Ahead Market that is not backed by physical load; (2) a Virtual Supply Offer, which is an offer submitted by a market participant in the Day-Ahead Market to sell energy not supported by a physical injection or reduction in withdrawals in commitment by a resource. An FTR is a financial contract that entitles its holder to a stream of payments, or charges, based on transmission congestion charges calculated in the MISO's Day-Ahead Market. A market participant can acquire an FTR from several sources: the annual or monthly FTR allocation based on existing entitlements, the annual or monthly FTR auction, the FTR secondary market or FTRs granted in conjunction with a transmission service request. An FTR is structured to hedge a market participant's exposure to uncertain cash flows resulting from congestion of the transmission system. Profits from virtual transactions were $1.2 million in 2006 compared with $12.7 million in 2005 as the MISO market matured and became more efficient and as a result of a reduction in virtual transactions due to uncertainties related to the status of Revenue Sufficiency Guarantee charges in the MISO's Transmission and Energy Markets Tariff. In 2006, we recorded a net loss on purchased power resold of $1.8 million compared with a net gain of $2.7 million in 2005. Of the $2.9 million in net mark-to-market gains recognized on open forward energy contracts at December 31, 2005, $2.1 million was realized and $0.8 million was reversed in the first nine months of 2006 as market prices on forward electric contracts declined in response to decreased demand for electricity due, in part, to regional winter weather that was milder than expected.

The $2.8 million increase in fuel costs in 2006 compared with 2005 reflects a 3.2% increase in the cost of fuel per mwh generated combined with a 1.8% increase in mwhs generated. Generation used for wholesale electric sales increased 3.4% while generation for retail sales increased 1.3% between the years. Fuel costs per mwh increased at the Coyote Station and Hoot Lake Plant as a result of increases in coal and coal transportation costs between the periods. Much of the increase in coal and coal transportation costs is related to higher diesel fuel prices. The mix of available generation resources in 2006 compared with 2005 also contributed to the increase in the cost of fuel per mwh generated. Big Stone Plant's generation increased 12.9% between the years while Coyote Station's generation was down 5.9%. In the second quarter of 2006, Coyote Station, our lowest cost baseload plant, was off-line for five weeks for scheduled maintenance. In the second quarter of 2005, the higher cost Big Stone Plant was shut down for seven weeks for scheduled maintenance.

The $0.5 million decrease in purchased power — system use in 2006 compared with 2005 is due to a 20.9% reduction in mwh purchases for system use mostly offset by a 25.2% increase in the cost per mwh purchased for system use.

The $3.6 million increase in other operation and maintenance expenses for 2006 compared with 2005 resulted primarily from $2.0 million in increased operating and maintenance costs at the electric utility's generation plants, including Coyote Station, which was shut down for five weeks of scheduled maintenance in the second quarter of 2006, and $1.4 million in increased costs related to contract work performed for other area utilities. Depreciation expense increased $1.4 million in 2006 compared with 2005 as a result of an increase in effective depreciation rates in 2006 and increases in electric plant in service. The $0.5 million decrease in property taxes reflects lower property valuations in Minnesota and South Dakota.

PLASTICS

The following table summarizes the results of operations for our plastics segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 149,012	(9)	$ 163,135	3	$ 158,548
Cost of Goods Sold	124,344	(2)	126,374	4	121,245
Operating Expenses	7,223	(29)	10,239	(6)	10,939
Depreciation and Amortization	3,083	10	2,815	12	2,511
Operating Income	$ 14,362	(39)	$ 23,707	(1)	$ 23,853

2007 compared with 2006

The $14.1 million decrease in plastics operating revenues in 2007 compared with 2006 reflects an 18.8% decrease in the price per pound of pipe sold, partially offset by a 12.5% increase in pounds of pipe sold between the years. The decrease in pipe prices and cost of goods sold reflects the effect of a 15.7% decrease in PVC resin prices between the years. The $3.0 million decrease in plastics segment operating expenses reflects a decrease in employee incentives directly related to the decreases in operating margins between the years. The increase in depreciation and amortization expense is the result of $5.5 million in capital additions in 2006, mainly for production equipment.

2006 compared with 2005

The $4.6 million increase in plastics operating revenues in 2006 compared with 2005 reflects a 12.6% increase in the price per pound of PVC and polyethylene pipe sold offset by an 8.8% decrease in pounds of pipe sold between the years. The increase in prices reflects the effect of a 13.7% increase in PVC resin costs per pound of PVC pipe shipped between the years. The decrease in pounds of pipe sold reflects a significant decrease in sales in the third and fourth quarters of 2006 compared with the third and fourth quarters of 2005, reflecting record demand for PVC pipe in the last half of 2005, as sales were affected by concerns over the adequacy of resin supply following the 2005 Gulf Coast hurricanes. The increase in cost of goods sold is a result of higher resin costs. The decrease in plastics segment operating expenses is due to lower selling, general and administrative expenses between the years. The increase in depreciation and amortization expense is related to capital additions in 2005 and 2006, mainly for production equipment.

MANUFACTURING

The following table summarizes the results of operations for our manufacturing segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 381,599	22	$ 311,811	28	$ 244,311
Cost of Goods Sold	300,146	22	246,649	27	194,264
Operating Expenses	35,278	33	26,508	11	23,872
Depreciation and Amortization	13,124	18	11,076	17	9,447
Operating Income	$ 33,051	20	$ 27,578	65	$ 16,728

2007 compared with 2006

The increase in revenues in our manufacturing segment in 2007 compared with 2006 relates to the following:

- Revenues at DMI Industries, Inc. (DMI), our manufacturer of wind towers, increased $48.0 million (35.2%) as a result of increased productivity at the West Fargo plant and increased production levels at the Ft. Erie plant compared with initial start-up levels beginning in May 2006.
- Revenues at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment manufacturer, increased $15.9 million (26.4%) between the years due to increased production and sales of commercial products and higher residential sales during the peak selling season. The Aviva Sports product line, acquired by ShoreMaster in February 2007, contributed $3.7 million to the increase in revenues.
- Revenues at BTD Manufacturing Inc. (BTD), our metal parts stamping and fabrication company, increased $3.5 million (4.5%) between the years, mainly as a result of the May 2007 acquisition of Pro Engineering, LLC (Pro Engineering).
- Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased $2.4 million (6.4%) between the years as a result of greater demand for both custom and horticultural products.

The increase in cost of goods sold in our manufacturing segment in 2007 compared with 2006 relates to the following:

- Cost of goods sold at DMI increased $39.8 million between the years, including increases of $30.4 million in material and supplies, $6.8 million in labor and benefit costs and $2.6 million in other direct manufacturing costs. The increase in cost of goods sold is directly related to DMI’s increase in production and sales activity, including operations at the Ft. Erie facilities which commenced in May 2006.
- Cost of goods sold at ShoreMaster increased $9.2 million between the years as a result of increases in material and labor costs directly related to the increase in commercial and residential product sales as well as the acquisition of the Aviva Sports product line in February 2007, which contributed $2.9 million to cost of goods sold in 2007.
- Cost of goods sold at BTD increased $2.8 million between the years as a result of the acquisition of Pro Engineering in May 2007, partially offset by a decrease in costs at BTD’s other manufacturing facilities related to a decrease in unit sales between the years.
- Cost of goods sold at T.O. Plastics increased $2.1 million, mainly driven by an increase in volume, as compared to 2006, and higher material costs.

The increase in operating expenses in our manufacturing segment in 2007 compared with 2006 relates to the following:

- Operating expenses at DMI increased $3.0 million, including $2.0 million in 2007 pre-production start-up costs at its new plant in Oklahoma and increases in expenses related to full operations at the Ft. Erie facility. The new plant in Oklahoma started producing towers in January 2008.
- Operating expenses at ShoreMaster increased $3.9 million as a result of increases in labor, benefits, sales expenses and professional services, of which $1.7 million is related to the Aviva Sports product line acquired in February 2007 and $1.3 million is related to facility relocation and legal expenses.
- Operating expenses at BTD increased $1.3 million between the years as a result of increases in labor and other

expenses, mainly related to the acquisition of Pro Engineering in May 2007, and the reduction of a legal settlement reserve in 2006.

- Operating expenses at T.O. Plastics increased by $0.6 million between the years mainly as a result of leadership succession costs and increases in professional service expenditures.

Depreciation expense increased between the years mainly as a result of 2006 capital additions at DMI's Ft. Erie and West Fargo plants.

2006 compared with 2005

The increase in revenues in our manufacturing segment in 2006 compared with 2005 relates to the following:

- Revenues at DMI increased $64.0 million (88.4%) as a result of increases in production and sales activity due in part to plant additions, including initial operations at the Ft. Erie, Ontario facility which generated $25.3 million in revenue in 2006, its first year of operations, and continued improvements in productivity and capacity utilization.

- Revenues at ShoreMaster increased $3.2 million (5.7%) between the years due to price increases driven by higher material costs (especially aluminum) and due to the acquisition of Southeast Floating Docks in May 2005.

- Revenues at T.O. Plastics increased $0.7 million (1.9%) between the periods as a result of a 0.9% increase in unit sales combined with a 1.5% increase in revenue per unit sold.

- Revenues at BTD decreased $0.4 million (0.5%) between the periods. However, BTD's operating income increased $3.6 million due, in part, to productivity improvements between the years.

The increase in cost of goods sold in our manufacturing segment in 2006 compared with 2005 relates to the following:

- Cost of goods sold at DMI increased $51.5 million between the years, including increases of $39.6 million in material costs, $9.2 million in labor and benefit costs and $2.7 million in tools and supplies expenditures. The increase in cost of goods sold is directly related to the increase in DMI's production and sales activity and initial operation and start up costs at its Ft. Erie facility.

- Cost of goods sold at ShoreMaster increased $2.4 million between the years as a result of increases in labor, material (especially aluminum) and other direct costs and a full year of operations relating to the acquisition of Southeast Floating Docks, which occurred in May 2005.

- Cost of goods sold at T.O. Plastics increased $2.0 million, reflecting $1.0 million in material cost increases and $0.8 million in increased labor and benefit costs between the years.

- Cost of goods sold at BTD decreased $3.3 million between the years mainly due to a decrease in labor costs between the years due to a reduction in the number of production employees, a decrease in overtime pay between the years and a reduction in production hours in December 2006. Productivity gains at BTD were achieved through efforts to better utilize and allocate available labor resources.

The increase in operating expenses in our manufacturing segment in 2006 compared with 2005 relates to the following:

- Operating expenses at DMI increased $2.7 million as a result of increases in labor, professional services and maintenance expenses mainly related to initial operation and start-up costs at the Ft. Erie plant.

- ShoreMaster's operating expenses increased $0.2 million between the years.

- T.O. Plastics' operating expenses increased $0.2 million between the years.

- BTD's operating expenses decreased $0.4 million between the years.

Depreciation expense increased between the years as a result of $21.1 million in capital additions from October 2005 through September 2006 at all four manufacturing companies. Capital additions at DMI's Ft. Erie plant totaled $8.0 million in 2006.

HEALTH SERVICES

The following table summarizes the results of operations for our health services segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 130,670	(3)	$ 135,051	9	$ 123,991
Cost of Goods Sold	99,612	(4)	104,108	15	90,327
Operating Expenses	23,691	4	22,745	3	21,989
Depreciation and Amortization	3,937	8	3,660	(9)	4,038
Operating Income	$ 3,430	(24)	$ 4,538	(41)	$ 7,637

2007 compared with 2006

The $4.4 million decrease in health services operating revenues in 2007 compared with 2006 reflects a $3.2 million decrease in revenues from scanning and other related services as a result of a $2.8 million decrease in revenues from rental and interim installations and transportation services and a 9.2% decrease in the number of scans performed between the years. Revenues from equipment sales and servicing decreased $1.2 million between the years as a decrease in traditional dealership distribution of products was mostly offset by increases in manufacturer representative commissions on more manufacturer-direct sales. The decrease in health services revenue was more than offset by the decrease in health services cost of goods sold due to the decrease in traditional dealership distribution of products and $3.2 million in decreases to labor, warranty and other direct costs of sales. The $0.9 million increase in operating expenses is mainly due to increased labor and sales and marketing expenditures. The increase in depreciation and amortization expense is due to capital additions in 2006 and 2007.

2006 compared with 2005

The $11.1 million increase in health services operating revenues in 2006 compared with 2005 reflects an $8.0 million increase in imaging revenues combined with a $3.1 million increase in revenues from sales and servicing of diagnostic imaging equipment. On the imaging side of the business, $3.5 million of the $8.0 million increase in revenue came from imaging services where the revenue per scan increased 15.7% between the years while the number of scans completed decreased 8.9%. Revenues from rentals and interim installations of scanning equipment along with providing technical support services for those rental and interim installations increased $4.5 million between the years. The increase in health services revenue was more than offset by the $13.8 million increase in health services cost of goods sold, mainly as a result of increases in costs of equipment purchased for resale, increases in unit rental and sublease costs related to units that were out of service in the first six months of 2006 and increases in labor and other direct costs. The $0.8 million increase in operating expenses is mainly due to increases in property tax expenses. The $0.4 million decrease in depreciation and amortization expense is the result of certain assets reaching the ends of their depreciable lives. When these assets are replaced, they are generally replaced with assets leased under operating leases.

FOOD INGREDIENT PROCESSING

The following table summarizes the results of operations for our food ingredient processing segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 70,440	56	$ 45,084	17	$ 38,501
Cost of Goods Sold	56,591	28	44,233	43	30,930
Operating Expenses	3,135	7	2,920	15	2,533
Depreciation and Amortization	3,952	5	3,759	11	3,399
Operating Income (Loss)	$ 6,762	216	$ (5,828)	(456)	$ 1,639

2007 compared with 2006

The $25.4 million increase in food ingredient processing revenues in 2007 compared with 2006 reflects a 29.5% increase in pounds of product sold combined with a 20.7% increase in the price per pound sold. A reduction in the value of the U.S. dollar relative to certain foreign currencies in 2007 and a poor European potato crop in 2006 led to favorable export pricing and sales increases in Europe, Latin America and the Pacific Rim in 2007. The increase in revenues was only partially offset by a 27.9% increase in cost of goods sold. The cost per pound of product sold decreased 1.2% between the years. The increase in operating expenses between the years is mainly due to increases in employee benefit and travel expenses. The increase in depreciation and amortization expense is related to $1.8 million in capital additions in 2006.

2006 compared with 2005

The $6.6 million increase in food ingredient processing revenues in 2006 compared with 2005 reflects a 15.3% increase in sales price per pound of product combined with a 1.5% increase in pounds of product sold between the years. The food ingredient processing segment was negatively impacted by raw potato supply shortages in Idaho and Prince Edward Island in 2006. Higher than expected raw product costs related to the supply shortages resulted in operating inefficiencies and a 40.8% increase in the cost per pound of product sold. The increase in operating expenses is due to an increase in selling and administrative expenses between the years. Consistent with trends in the industry, operating income for 2006 was less than expected due to raw potato supply shortages, increasing raw material costs and the increasing value of the Canadian dollar relative to the U.S. dollar.

OTHER BUSINESS OPERATIONS

The following table summarizes the results of operations for our other business operations segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 185,730	28	$ 145,603	38	$ 105,821
Cost of Goods Sold	133,393	45	91,806	36	67,711
Operating Expenses	42,462	1	41,867	16	36,020
Depreciation and Amortization	2,058	(12)	2,330	5	2,225
Operating Income (Loss)	$ 7,817	(19)	$ 9,600		$ (135)

2007 compared with 2006

The increase in operating revenues in 2007 compared with 2006 in our other business operations is due to the following:

- Revenues at Midwest Construction Services, Inc. (MCS), our electrical design and construction services company, increased $22.9 million (49.9%) between the years as a result of an increase in volume of jobs in 2007.
- Revenues at Foley Company (Foley), a mechanical and prime contractor on industrial projects, increased $17.3 million (26.9%) between the years due to an increase in the volume of jobs in progress.
- Revenues at E.W. Wylie Corporation (Wylie), our flatbed trucking company, were unchanged between the years.

The increase in cost of goods sold in 2007 compared with 2006 is due to the following:

- Cost of goods sold at MCS increased $25.0 million mainly due to increases in material, subcontractor, direct labor and insurance costs related to the increase in volume of jobs between the years. Lower than expected margins on certain construction projects at MCS was the main factor contributing to the decrease in operating income between the years.
- Cost of goods sold at Foley increased $16.6 million mainly due to increases in direct labor, employee benefits, subcontractor and material costs as a result of the increased volume of work performed between the years.

The increase in operating expenses in 2007 compared with 2006 is due to the following:

- Operating expenses at MCS were unchanged between the years.
- Operating expenses at Foley increased $0.5 million between the years as a result of increased labor, benefit and insurance expenses. Also, Foley’s 2006 expenses reflect the recovery of $0.2 million in bad debts.
- Operating expenses at Wylie were unchanged between the years.

The decrease in depreciation and amortization expense in 2007 compared with 2006 reflects the effects of a decision by Wylie to lease rather than buy replacement trucks for its fleet.

2006 compared with 2005

The increase in operating revenues in our other business operations in 2006 compared with 2005 is due to the following:

- Revenues at Foley increased $33.3 million (106.4%) due to an increase in the volume of work performed between the years.
- Revenues at Wylie increased $4.5 million (14.8%) between the years mainly due to an 8.4% net increase in miles driven by owner-operated and company-operated trucks. Miles driven by owner-operated trucks increased 50.3% while miles driven by company-operated trucks decreased 9.3% between the periods. Wylie's increased revenues also reflect higher rates related to increased fuel costs recovered through fuel surcharges between the years for both owner-operated and company-operated trucks.
- Revenues at MCS increased $2.3 million (5.2%) between the years as a result of increased activity on several wind projects in the fourth quarter of 2006.

The increase in cost of goods sold in our other business operations in 2006 compared with 2005 is due to the following:

- Foley's cost of goods sold increased $28.3 million mainly in the areas of materials, subcontractor and labor costs as a result of an increase in the volume of work performed between the years.
- Cost of goods sold at MCS decreased $4.2 million mainly due to a reduction in material and labor costs between the years mostly related to a job completed in 2005 on which large losses were incurred as a result of higher than expected costs.

The increase in operating expenses in the other business operations segment is due to the following:

- Wylie's revenue increase was entirely offset by a $4.5 million increase in operating expenses, including $4.0 million in contractor costs related to higher fuel costs combined with an increase in miles driven by owner-operated trucks between the years and $0.5 million in increased insurance costs.
- Foley's operating expenses increased $0.7 million between the years as a result of increases in employee benefit costs.
- MCS operating expenses increased $1.0 million between the years, mainly due to increases in employee benefit costs.

The increase in depreciation and amortization expense in 2006 compared with 2005 is mainly related to equipment purchases at Foley in 2005 and 2006.

CORPORATE

Corporate includes items such as corporate staff and overhead costs, the results of the company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate is not an operating segment. Rather it is added to operating segment totals to reconcile to totals on our consolidated statements of income.

(in thousands)	2007	% change	2006	% change	2005
Operating Expenses	$9,824	(13)	$11,322	(22)	$14,572
Depreciation and Amortization	579	(1)	587	33	441

2007 compared with 2006

Corporate operating expenses decreased $1.5 million as a result of a combination of lower insurance costs at our captive insurance company and lower health insurance plan costs.

2006 compared with 2005

Corporate operating expenses decreased $3.2 million as a result of lower health insurance plan costs, improved claims experience in our captive insurance company and a gain on the sale of property in 2006.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS

Other income and deductions increased by $2.5 million in 2007 compared with 2006 and decreased by $2.2 million in 2006 compared with 2005, mainly due to a noncash charge of $3.3 million in 2006 related to the disallowance of a portion of capitalized costs of funds used during construction from the electric utility's rate base.

CONSOLIDATED INTEREST CHARGES

Interest expense increased $1.4 million in 2007 compared with 2006 as a result of a net increase of $87 million in long-term debt in 2007. Short-term debt interest expense increased by $1.8 million in 2007 as a result of an increase in the average daily balance of short-term debt outstanding and higher interest rates. Increases in interest expense on both long-term and short-term debt were partially offset by a $2.4 million increase in capitalized interest in 2007. Interest expense increased $1.0 million in 2006 compared with 2005 primarily as a result of increased interest rates on short-term debt.

CONSOLIDATED INCOME TAXES

The 3.2% increase in income tax expense from continuing operations in 2007 compared to 2006 is due, in part, to a 5.2% increase in income from continuing operations before income taxes. Our effective tax rate on income from continuing operations was 34.1% for 2007 compared with 34.8% for 2006.

The 3.2% decrease in income tax expense from continuing operations in 2006 compared to 2005 is due, in part, to a 4.9% decrease in income from continuing operations before income taxes. Our effective tax rate on income from continuing operations was 34.8% for 2006 compared with 34.2% for 2005.

DISCONTINUED OPERATIONS

In 2006, we sold the natural gas marketing operations of OTESCO, our energy services subsidiary. Discontinued operations includes the operating results of OTESCO's natural gas marketing operations for 2006 and 2005. Discontinued operations also includes an after-tax gain on the sale of OTESCO's natural gas marketing operations of $0.3 million in 2006.

In 2005, we sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Discontinued operations includes the operating results of MIS, SGS and CLC for 2005. Discontinued operations also includes an after-tax gain on the sale of MIS of $11.9 million, an after-tax loss on the sale of SGS of $1.7 million and an after-tax loss on the sale of CLC of $0.2 million in 2005.

The following table presents operating revenues, expenses, including interest and other income and deductions, and income taxes, included on a net basis in income from discontinued operations on our 2006 and 2005 consolidated statements of income.

(in thousands)	2006	2005
Operating Revenues	$ 28,234	$ 80,988
Expenses	28,180	81,601
Goodwill Impairment Loss	—	1,003
Income Tax Expense (Benefit)	28	(261)
Income (Loss) from Discontinued Operations	$ 26	$ (1,355)

The $1.0 million goodwill impairment loss in 2005 was for the write-off of goodwill at OTESCO related to its natural gas marketing operations in the third quarter of 2005 as a result of a reassessment of its future cash flows in light of rising natural gas prices and greater market volatility in future prices for natural gas.

The following table presents the pre-tax and net-of-tax gains and losses recorded on the sales of OTESCO's natural gas marketing operations in 2006 and MIS, SGS and CLC in 2005.

	2006	2005			
(in thousands)	OTESCO-gas	MIS	SGS	CLC	Total
Gain (Loss) on Sale	$ 560	$ 19,025	$ (2,919)	$ (271)	$ 15,835
Income Tax (Expense) Benefit	(224)	(7,107)	1,168	108	(5,831)
Net Gain (Loss) on Sale	$ 336	$ 11,918	$ (1,751)	$ (163)	$ 10,004

IMPACT OF INFLATION

The electric utility operates under regulatory provisions that allow price changes in fuel and certain purchased power costs to be passed to most retail customers through automatic adjustments to its rate schedules under fuel clause adjustments. Other increases in the cost of electric service must be recovered through timely filings for electric rate increases with the appropriate regulatory agency.

Our plastics, manufacturing, health services, food ingredient processing, and other business operations consist entirely of unregulated businesses. Increased operating costs are reflected in product or services pricing with any limitations on price increases determined by the marketplace. Raw material costs, labor costs and interest rates are important components of costs for companies in these segments. Any or all of these components could be impacted by inflation or other pricing pressures, with a possible adverse effect on our profitability, especially where increases in these costs exceed price increases on finished products. In recent years, our operating companies have faced strong inflationary and other pricing pressures with respect to steel, fuel, resin, lumber, concrete, aluminum and health care costs, which have been partially mitigated by pricing adjustments.

2008 EXPECTATIONS

We anticipate 2008 diluted earnings per share to be in a range from $1.85 to $2.10. Contributing to the earnings guidance for 2008 are the following items:

- We expect increased levels of net income from our electric segment in 2008. This increase is based on having lower cost generation available for the year, as there are no plant shutdowns planned for Big Stone Plant or Coyote Station in 2008, and additional rate base investment from the Langdon wind project. The increase also assumes the interim rate increase of $7.1 million, or 5.41%, which is part of the rate case filed with the MPUC. These interim rates remain in effect for all Minnesota customers until the MPUC makes a final determination on the electric utility's request, which is expected to occur by August 1, 2008. If final rates are lower than interim rates, the electric utility will refund customers the difference with interest. If final rates are higher than interim rates, the higher rates will become effective as of the date of the MPUC order approving those rates.
- We expect our plastics segment's 2008 performance to be at or below normal levels. Announced capacity expansions are not expected to come on line until the fourth quarter of 2008.
- We expect increased levels of net income in our manufacturing segment in 2008 as a result of increased capacity and productivity related to recent expansions and acquisitions, and the start-up of DMI's wind tower manufacturing plant in Oklahoma in 2008. Backlog in place in the manufacturing segment to support 2008 revenues is approximately $295 million compared with $241 million one year ago. The wind energy tower manufacturing business accounts for a substantial portion of the 2008 backlog.
- We expect improvement in net income from our health services segment in 2008 as it focuses on improving its mix of imaging assets and asset utilization rates.
- We expect our food ingredient processing business to have increased net income due to higher operating margins in 2008. This business has backlog in place for 2008 of 51.5 million pounds compared with 52.8 million pounds one year ago.
- We expect our other business operations segment to have higher net income in 2008 compared with 2007. Backlog in place for the construction businesses is $77 million for 2008 compared with $74 million for the same period one year ago.
- Corporate general and administrative costs are expected to increase in 2008.

Our outlook for 2008 is dependent on a variety of factors and is subject to the risks and uncertainties discussed under "Risk Factors and Cautionary Statements."

LIQUIDITY

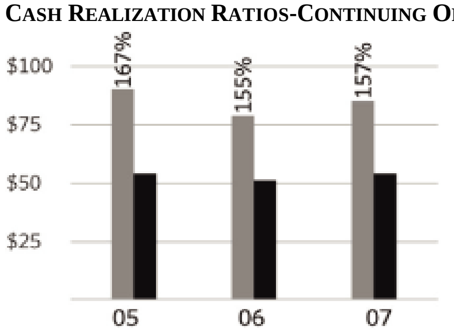
We believe our financial condition is strong and that our cash, other liquid assets, operating cash flows, access to capital markets through our universal shelf registration and borrowing ability because of solid credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. Additional equity or debt financing will be required in the period 2008 through 2012 given our current capital expansion plans over this period. See "Capital Resources" section for further discussion. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by short-term and long-term debt ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

We have achieved a high degree of long-term liquidity by maintaining desired capitalization ratios and solid credit ratings, implementing cost-containment programs and investing in projects that provide returns in excess of our weighted average cost of capital.

Cash provided by operating activities of continuing operations was $84.8 million in 2007 compared with $79.2 million in 2006. The $5.6 million increase in cash provided by operating activities of continuing operations reflects a $2.8 million increase in net income and a $2.8 million increase in depreciation and amortization expense.

Cash used for working capital items was $28.5 million in 2007 compared with $30.4 million in 2006, a decrease of $1.9 million. Major uses of funds for working capital items in 2007 were an increase in receivables of $18.9 million, an increase in other current assets of $14.6 million and a decrease in payables of $2.5 million, offset by a decrease in inventories of $8.4 million. The increase in receivables includes $14.8 million at DMI related to increased sales of wind towers and $5.0 million from our construction companies related to increased activity and billings in 2007. The increase in other current assets includes an $8.6 million increase in accrued FCA and unbilled revenues at the electric utility, mainly related to an increase in purchased power costs in the fourth quarter of 2007 to replace generation lost during a scheduled major maintenance shutdown of our Big Stone Plant. The increase in other current assets also includes an increase in costs in excess of billings of $2.8 million at DMI related to increased levels of wind tower production and $2.1 million at the construction companies related to an increase in work volume between the years. DMI's costs and estimated earnings in excess of billings stood at $36.2 million as of December 31, 2007 related to costs incurred on work in progress on major wind tower contracts. Our cash flows from operations will be positively impacted as these amounts are billed and collected. The decrease in inventories reflects reductions in the value of finished goods and raw materials inventory of $5.3 million at our plastic pipe companies due to a 19% decrease in pounds of pipe in inventory combined with a decrease in resin prices between the years. The decrease in inventories also reflects a $2.3 million decrease in raw material and work in process inventory at DMI due to better inventory management.

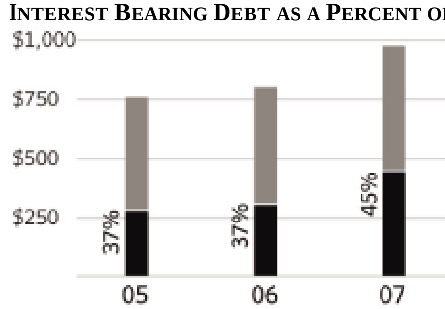
CASH REALIZATION RATIOS-CONTINUING OPERATIONS



The cash realization ratio represents cash flows from continuing operations expressed as a percent of net income from continuing operations.

■ Cash Flows from Continuing Operations
■ Net Income from Continuing Operations

INTEREST BEARING DEBT AS A PERCENT OF TOTAL CAPITAL



Otter Tail has maintained a 37-45 percent interest-bearing debt to total capital ratio for the past five years.

■ Total Capital
■ Interest-Bearing Debt (includes short-term debt)

Net cash used in investing activities of continuing operations was $164.0 million in 2007 compared with $67.5 million in 2006. Cash used for capital expenditures increased by $92.5 million between the years. Cash used for capital expenditures at the electric utility increased by $69.1 million between the years mainly related to construction of 27 wind turbines near Langdon, North Dakota and replacement of the flue-gas treatment system at our Big Stone Plant in 2007. Cash used for capital expenditures at DMI increased $20.8 million between the years mainly due to the purchase of property and equipment for a new wind tower manufacturing facility near Tulsa, Oklahoma, which became operational in January 2008. We completed two acquisitions in 2007 for a combined purchase price of $6.8 million.

Net cash provided by financing activities was $113.2 million in 2007 compared with net cash used in financing activities of $13.3 million in 2006. We received proceeds of $203.4 million in cash from the issuance of debt, net of debt issuance expenses, and paid $118.2 million to retire or refinance debt in 2007. We also increased borrowings under our line of credit by $56.1 million in 2007 and received $7.7 million in proceeds from the issuance of 298,601 shares of common stock for stock options exercised in 2007. Proceeds from borrowings and common stock issuance in excess of cash used to retire long-term debt were used to fund construction expenditures and acquisitions along with cash from operating activities in excess of dividends paid. We paid $35.5 million in common and preferred dividends in 2007 compared with $34.6 million in 2006. The increase is due to an increase in common shares outstanding and a two cent per share increase in common dividends paid between the years.

CAPITAL REQUIREMENTS

We have a capital expenditure program for expanding, upgrading and improving our plants and operating equipment. Typical uses of cash for capital expenditures are investments in electric generation facilities, transmission and distribution lines, manufacturing facilities and upgrades, equipment used in the manufacturing process, purchase of diagnostic medical equipment, transportation equipment and computer hardware and information systems. The capital expenditure program is subject to review and is revised in light of changes in demands for energy, technology, environmental laws, regulatory changes, business expansion opportunities, the costs of labor, materials and equipment and our consolidated financial condition.

Consolidated capital expenditures were $162 million in 2007, $69 million in 2006 and $60 million in 2005. Estimated capital expenditures for 2008 are $135 million and the total capital expenditures for the five-year period 2008 through 2012 are estimated to be approximately $899 million, which includes $336 million for our share of expected expenditures for construction of the planned Big Stone II electric generating plant and related transmission assets if all necessary permits and approvals are granted on a timely basis, and $67 million for CapX 2020 projects. The breakdown of 2005, 2006 and 2007 actual and 2008 through 2012 estimated capital expenditures by segment is as follows:

(in millions)	2005	2006	2007	2008	2008-2012
Electric	$ 30	$ 35	$ 104	$ 94	$ 759
Plastics	4	5	3	13	21
Manufacturing	16	20	43	18	80
Health Services	3	5	5	2	11
Food Ingredient Processing	3	2	—	4	18
Other Business Operations	4	2	6	4	9
Corporate	—	—	1	—	1
Total	$ 60	$ 69	$ 162	$ 135	$ 899

The following table summarizes our contractual obligations at December 31, 2007 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-Term Debt Obligations	$ 346	$ 3	$ 6	$ 101	$ 236
Interest on Long-Term Debt Obligations	273	21	41	35	176
Operating Lease Obligations	138	43	69	19	7
Capacity and Energy Requirements	162	23	35	11	93
Coal Contracts (required minimums)	183	51	89	16	27
Postretirement Benefit Obligations	56	3	7	7	39
Other Purchase Obligations	43	43	—	—	—
Total Contractual Cash Obligations	$ 1,201	$ 187	$ 247	$ 189	$ 578

Interest on $10.4 million of variable-rate debt outstanding on December 31, 2007 was projected based on the interest rates applicable to that debt instrument on December 31, 2007. Postretirement Benefit Obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan, but do not include amounts to fund our noncontributory funded pension plan as we are not currently required to make a contribution to that plan.

CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, our universal shelf registration, unused lines of credit, strong financial coverages, solid credit ratings, and alternative financing arrangements such as leasing. We have the ability to issue up to $256 million of common stock, cumulative preferred stock, debt and certain other securities from time to time under our universal shelf registration statement filed with the Securities and Exchange Commission. Additional equity or debt financing will be required in the period 2008 through 2012 given the expansion plans related to our electric segment to fund the construction of the proposed new Big Stone II generating station at the Big Stone Plant site and proposed new wind generation projects, in the event we decide to reduce borrowings under our lines of credit, refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

Our $150 million line of credit pursuant to a Credit Agreement dated as of April 26, 2006 with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West was scheduled to expire on April 26, 2009 but was terminated and replaced by a new $200 million credit agreement (the Varistar Credit Agreement) entered into by Varistar Corporation (Varistar), our wholly-owned subsidiary, on October 2, 2007. Varistar entered into the Varistar Credit Agreement with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. The Varistar Credit Agreement is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Varistar Credit Agreement expires on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on Varistar's adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Outstanding letters of credit issued by Varistar can reduce the amount available for borrowing under the line by up to $30 million. As of December 31, 2007, $95.0 million of the $200 million line of credit was in use and $14.9 million was restricted from use to cover outstanding letters of credit.

Otter Tail Corporation, dba Otter Tail Power Company and U.S. Bank National Association entered into a Credit Agreement (the Electric Utility Credit Agreement) providing for a separate $75 million line of credit. This line of credit is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on September 1, 2008. As of December 31, 2007 no money was borrowed under the Electric Utility Credit Agreement.

At closings completed in August 2007 and October 2007, we issued $155 million aggregate principal amount of senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of

6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The net proceeds from this initial closing were used to repay borrowings under our $150 million line of credit that was terminated on October 2, 2007. We issued and sold the remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of our 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of our 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

In February 2007, we entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which we agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of our senior notes due November 30, 2017 (the Cascade Note). On December 14, 2007 we issued the Cascade Note. The Cascade Note bears interest at a rate of 5.778% per annum. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of our $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The proceeds of this financing were used to redeem our $50 million 6.375% Senior Debentures due December 1, 2007. Cascade owned approximately 8.6% of our outstanding common stock as of December 31, 2007.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement and the 2001 Note Purchase Agreement states we may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require us to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states we must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company.

The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement contain a number of restrictions on us and our subsidiaries. In each case these include restrictions on our ability and the ability of our subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

The Electric Utility Company Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement and the Lombard US Equipment Finance note contain covenants by us not to permit our debt-to-total capitalization ratio to exceed 60% or permit our interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, our interest coverage ratio) to be less than 1.5 to 1. The note purchase agreements further restrict us from allowing our priority debt to exceed 20% of total capitalization. Financial covenants in the Varistar Credit Agreement require Varistar to maintain a fixed charge coverage ratio of not less than 1.25 to 1 and to not permit its cash flow leverage ratio to exceed 3.0 to 1. We and Varistar were in compliance with all of the covenants under our financing agreements as of December 31, 2007.

Our obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of our subsidiaries. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Our Grant County and Mercer County Pollution Control Refunding Revenue Bonds require that we grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, a security interest in the assets of the electric utility if the rating on our senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's).

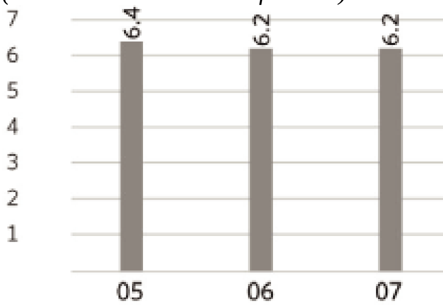
Our securities ratings at December 31, 2007 were:

	Moody's Investors Service	Standard & Poor's
Senior Unsecured Debt	A3	BBB+
Preferred Stock	Baa2	BBB-
Outlook	Negative	Negative

In July 2007, Moody’s changed its outlook on our company from stable to negative, citing risks of recovery associated with planned capital expenditures in the electric segment as a major factor contributing to its outlook change. In September 2007, Standard & Poor’s changed its outlook on our company from stable to negative, citing continued growth of nonregulated businesses and a large capital spending program in the electric segment as the reasons for its outlook change. Our disclosure of these securities ratings is not a recommendation to buy, sell or hold our securities. Downgrades in these securities ratings could adversely affect our company. Further, downgrades could increase our borrowing costs resulting in possible reductions to net income in future periods and increase the risk of default on our debt obligations.

Our ratio of earnings to fixed charges from continuing operations, which includes imputed finance costs on operating leases, was 3.5x for 2007 compared to 3.9x for 2006 and our long-term debt interest coverage ratio before taxes was 6.2x for both 2007 and 2006. During 2008, we expect these coverage ratios to be consistent with 2007 levels assuming 2008 net income meets our expectations.

LONG-TERM DEBT INTEREST COVERAGE
(times-interest earned before tax)



Otter Tail has maintained coverage ratios in excess of its debt covenant requirements.

OFF-BALANCE-SHEET ARRANGEMENTS

We do not have any off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

RISK FACTORS AND CAUTIONARY STATEMENTS

We are including the following factors and cautionary statements in this Annual Report to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by us or on our behalf. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All these forward-looking statements, whether written or oral and whether made by us or on our behalf, are also expressly qualified by these factors and cautionary statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of the factors, nor can we assess the effect of each factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The following factors and the other matters discussed herein are important factors that could cause actual results or outcomes for our company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

GENERAL

Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.

We are subject to federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health safety. These laws and regulations regulate the modification and operation of existing facilities, the construction and operation of new facilities and the proper storage, handling, cleanup and disposal of hazardous waste and toxic substances. Compliance with these legal requirements requires us to commit significant resources and funds toward environmental monitoring, installation and operation of pollution control equipment, payment of emission fees and securing environmental permits. Obtaining environmental permits can entail significant expense and cause substantial construction delays. Failure to comply with environmental laws and regulations, even if caused by factors beyond our control, may result in civil or criminal liabilities, penalties and fines.

Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

Volatile financial markets and changes in our debt ratings could restrict our ability to access capital and increase our borrowing costs and pension plan expenses.

We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are not able to access capital at competitive rates, the ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access one or more financial markets.

Changes in the U.S. capital markets could also have significant effects on our pension plan. Our pension income or expense is affected by factors including the market performance of the assets in the master pension trust maintained for the pension plans for some of our employees, the weighted average asset allocation and long-term rate of return of our pension plan assets, the discount rate used to determine the service and interest cost components of our net periodic pension cost and assumed rates of increase in our employees’ future compensation. If our pension plan assets do not achieve positive rates of return, or if our estimates and assumed rates are not accurate, our earnings may decrease because net periodic pension costs would rise and we could be required to provide additional funds to cover our obligations to employees under the pension plan.

Our plans to grow and diversify through acquisitions may not be successful, which could result in poor financial performance.

As part of our business strategy, we intend to acquire new businesses. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. If we are unable to make acquisitions, we may be unable to realize the growth we anticipate. Future acquisitions could involve numerous risks including: difficulties in integrating the operations, services, products and personnel of the acquired business; and the potential loss of key employees, customers and suppliers of the acquired business. If we are unable to successfully manage these risks of an acquisition, we could face reductions in net income in future periods.

Our plans to grow our nonelectric businesses could be limited by state law.

Our plans to acquire and grow our nonelectric businesses could be adversely affected by legislation in one or more states that may attempt to limit the amount of diversification permitted in a holding company system that includes a regulated utility company or affiliated nonelectric companies.

ELECTRIC

We may experience fluctuations in revenues and expenses related to our electric operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to shareholders or scheduled payments on our debt obligations.

A number of factors, many of which are beyond our control, may contribute to fluctuations in our revenues and expenses from electric operations, causing our net income to fluctuate from period to period. These risks include fluctuations in the volume and price of sales of electricity to customers or other utilities, which may be affected by factors such as mergers and acquisitions of other utilities, geographic location of other utilities, transmission costs (including increased costs related to operations of regional transmission organizations), changes in the manner in which wholesale power is sold and purchased, unplanned interruptions at our generating plants, the effects of regulation and legislation, demographic changes in our customer base and changes in our customer demand or load growth. Electric wholesale margins have been significantly and adversely affected by increased efficiencies in the MISO market. Electric wholesale trading margins could also be adversely affected by losses due to trading activities. Other risks include weather conditions or changes in weather patterns (including severe weather that could result in damage to our assets), fuel and purchased power costs and the rate of economic growth or decline in our service areas. A decrease in revenues or an increase in expenses related to our electric operations may reduce the amount of funds available for our existing and future businesses, which could result in increased financing requirements, impair our ability to make expected distributions to shareholders or impair our ability to make scheduled payments on our debt obligations.

As of December 31, 2007 the electric utility has capitalized $8.2 million in costs related to the planned construction of a second electric generating unit at our Big Stone Plant site. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

Actions by the regulators of our electric operations could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.

We are subject to federal and state legislation, government regulations and regulatory actions that may have a negative impact on our business and results of operations. The electric rates that we are allowed to charge for our electric services are one of the most important items influencing our financial position, results of operations and liquidity. The rates that we charge our electric customers are subject to review and determination by state public utility commissions in Minnesota, North Dakota and South Dakota. We are also regulated by the Federal Energy Regulatory Commission. An adverse decision by one or more regulatory commissions concerning the level or method of determining electric utility rates, the authorized returns on equity, implementation of enforceable federal reliability standards or other regulatory matters, permitted business activities (such as ownership or operation of nonelectric businesses) or any prolonged delay in rendering a decision in a rate or other proceeding (including with respect to the recovery of capital expenditures in rates) could result in lower revenues and net income.

Future operating results of our electric segment will be impacted by the outcome of a rate case filed in Minnesota on October 1, 2007 requesting a final overall increase in Minnesota retail electric rates of 6.7%. The filing included a request for an interim rate increase of 5.4%, which went into effect on November 30, 2007. Interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the electric utility's request, which is expected by August 1, 2008. If final rates are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Certain costs currently included in the FCA in retail rates may be excluded from recovery through the FCA but may be subject to recovery through rates established in a general rate case. Further, all, or portions of, gross margins on asset-based wholesale electric sales may become subject to refund through the FCA as a result of a general rate case. Recovery of MISO schedule 16 and 17 administrative costs associated with providing electric service to Minnesota and North Dakota customers are currently being deferred pending the results of our current general rate case in Minnesota and our next general rate case in North Dakota scheduled to be filed in November or December of 2008. If we are not granted recovery of $1.4 million in deferred costs as of December 31, 2007 we could be required to recognize these costs immediately in expense at the time recovery is denied.

We may not be able to respond effectively to deregulation initiatives in the electric industry, which could result in reduced revenues and earnings.

We may not be able to respond in a timely or effective manner to the changes in the electric industry that may occur as a result of regulatory initiatives to increase wholesale competition. These regulatory initiatives may include further deregulation of the electric utility industry in wholesale markets. Although we do not expect retail competition to come to the states of Minnesota, North Dakota and South Dakota in the foreseeable future, we expect competitive forces in the electric supply segment of the electric business to continue to increase, which could reduce our revenues and earnings.

Our electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

Operation of electric generating facilities involves risks which can adversely affect energy output and efficiency levels. Most of our generating capacity is coal-fired. We rely on a limited number of suppliers of coal, making us vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. We are a captive rail shipper of the BNSF Railway for shipments of coal to our Big Stone and Hoot Lake plants, making us vulnerable to increased prices for coal transportation from a sole supplier. Higher fuel prices result in higher electric rates for our retail customers through fuel clause adjustments and could make us less competitive in wholesale electric markets. Operational risks also include facility shutdowns due to breakdown or failure of equipment or processes, labor disputes, operator error and catastrophic events such as fires, explosions, floods, intentional acts of destruction or other similar occurrences affecting our electric generating facilities. The loss of a major generating facility would require us to find other sources of supply, if available, and expose us to higher purchased power costs.

Changes to regulation of generating plant emissions, including but not limited to carbon dioxide (CO_2) emissions, could affect our operating costs and the costs of supplying electricity to our customers.

Existing or new laws or regulations addressing climate change or reductions of greenhouse gas emissions by federal or state authorities, such as mandated levels of renewable generation or mandatory reductions in CO_2 emission levels or taxes on CO_2 emissions, that result in increases in electric service costs could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the electric utility provides service or through increased market prices for electricity.

PLASTICS

Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for our plastics business.

We rely on a limited number of vendors to supply the PVC resin used in our plastics business. Two vendors accounted for approximately 95% of our total purchases of PVC resin in 2007 and approximately 99% of our total purchases of PVC resin in 2006. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which may increase the risk of a shortage of resin in the event of a hurricane or other natural disaster in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources are available.

We compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.

The plastic pipe industry is highly fragmented and competitive due to the large number of producers and the fungible nature of the product. We compete not only against other PVC pipe manufacturers, but also against ductile iron, steel, concrete and clay pipe manufacturers. Due to shipping costs, competition is usually regional instead of national in scope, and the principal areas of competition are a combination of price, service, warranty and product performance. Our inability to compete effectively in each of these areas and to distinguish our plastic pipe products from competing products may adversely affect the financial performance of our plastics business.

Reductions in PVC resin prices can negatively affect our plastics business.

The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower. Reductions in PVC resin prices could negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

MANUFACTURING

Competition from foreign and domestic manufacturers, the price and availability of raw materials, fluctuations in foreign currency exchange rates, the availability of production tax credits and general economic conditions could affect the revenues and earnings of our manufacturing businesses.

Our manufacturing businesses are subject to risks associated with competition from foreign and domestic manufacturers that have excess capacity, labor advantages and other capabilities that may place downward pressure on margins and profitability. Raw material costs for items such as steel, lumber, concrete, aluminum and resin have increased significantly and may continue to increase. Our manufacturers may not be able to pass on the cost of such increases to their respective customers. Each of our manufacturing companies has significant customers and concentrated sales to such customers. If our relationships with significant customers should change materially, it would be difficult to immediately and profitably replace lost sales. Fluctuations in foreign currency exchange rates could have a negative impact on the net income and competitive position of our wind tower manufacturing operations in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars. We believe the demand for wind towers that we manufacture will depend primarily on the existence of either renewable portfolio standards or the Federal Production Tax Credit for wind energy. This credit is scheduled to expire on December 31, 2008. Our wind tower manufacturer and electrical contractor could be adversely affected if the tax credit in not extended or renewed.

HEALTH SERVICES

Changes in the rates or methods of third-party reimbursements for our diagnostic imaging services could result in reduced demand for those services or create downward pricing pressure, which would decrease our revenues and earnings.

Our health services businesses derive significant revenue from direct billings to customers and third-party payors such as Medicare, Medicaid, managed care and private health insurance companies for our diagnostic imaging services. Moreover, customers who use our diagnostic imaging services generally rely on reimbursement from third-party payors. Adverse changes in the rates or methods of third-party reimbursements could reduce the number of procedures for which we or our customers can obtain reimbursement or the amounts reimbursed to us or our customers.

Our health services operations has a dealership and other agreements with Philips Medical from which it derives significant revenues from the sale and service of Philips Medical diagnostic imaging equipment.

This agreement can be terminated on 180 days written notice by either party for any reason. It also includes other compliance requirements. If this agreement were terminated within the notice provisions or we were not able to renew such agreements or comply with the agreement, the financial results of our health services operations would be adversely affected.

Technological change in the diagnostic imaging industry could reduce the demand for diagnostic imaging services and require our health services operations to incur significant costs to upgrade its equipment.

Although we believe substantially all of our diagnostic imaging systems can be upgraded to maintain their state-of-the-art character, the development of new technologies or refinements of existing technologies might make our existing systems technologically or economically obsolete, or cause a reduction in the value of, or reduce the need for, our systems.

Actions by regulators of our health services operations could result in monetary penalties or restrictions in our health services operations.

Our health services operations are subject to federal and state regulations relating to licensure, conduct of operations, ownership of facilities, addition of facilities and services and payment of services. Our failure to comply with these regulations, or our inability to obtain and maintain necessary regulatory approvals, may result in adverse actions by regulators with respect to our health services operations, which may include civil and criminal penalties, damages, fines, injunctions, operating restrictions or suspension of operations. Any such action could adversely affect our financial results. Courts and regulatory authorities have not fully interpreted a significant number of these laws and regulations, and this uncertainty in interpretation increases the risk that we may be found to be in violation. Any action brought against us for violation of these laws or regulations, even if successfully defended, may result in significant legal expenses and divert management's attention from the operation of our businesses.

FOOD INGREDIENT PROCESSING

Our company that processes dehydrated potato flakes, flour and granules, Idaho Pacific Holdings, Inc. (IPH), competes in a highly competitive market and is dependent on adequate sources of potatoes for processing.

The market for processed, dehydrated potato flakes, flour and granules is highly competitive. The profitability and success of our potato processing company is dependent on superior product quality, competitive product pricing, strong customer relationships, raw material costs, natural gas prices and availability and customer demand for finished goods. In most product categories, our company competes with numerous manufacturers of varying sizes in the United States.

The principal raw material used by our potato processing company is washed process-grade potatoes from growers. These potatoes are unsuitable for use in other markets due to imperfections. They are not subject to the United States Department of Agriculture's general requirements and expectations for size, shape or color. While our food ingredient processing company has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key growers and other factors. A loss or shortage of raw materials or the necessity of paying much higher prices for raw materials or natural gas could adversely affect the financial performance of this company. Fluctuations in foreign currency exchange rates could have a negative impact on our potato processing company's net income and competitive position because approximately 31% of its sales in 2007 were outside the United States and the Canadian plant pays its operating expenses in Canadian dollars.

We currently have $24.3 million of goodwill and a $3.3 million nonamortizable trade name recorded on our balance sheet related to the acquisition of IPH in 2004. If conditions of low sales prices, high energy and raw material costs and a shortage of raw potato supplies return, as experienced in 2006, and the increased value of the Canadian dollar relative to the U.S. dollar persists or operating margins do not improve according to our projections, the reductions in anticipated cash flows from this business may indicate that its fair value is less than its book value resulting in an impairment of goodwill and nonamortizable intangible assets and a corresponding charge against earnings.

OTHER BUSINESS OPERATIONS

Our construction companies may be unable to properly bid and perform on projects.

The profitability and success of our construction companies require us to identify, estimate and timely bid on profitable projects. The quantity and quality of projects up for bids at any time is uncertain. Additionally, once a project is awarded, we must be able to perform within cost estimates that were set when the bid was submitted and accepted. A significant failure or an inability to properly bid or perform on projects could lead to adverse financial results for our construction companies.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2007 we had limited exposure to market risk associated with interest rates and commodity prices and limited exposure to market risk associated with changes in foreign currency exchange rates. Outstanding trade accounts receivable of the Canadian operations of IPH are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 31% of IPH sales in 2007 were outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars. DMI has market risk related to changes in foreign currency exchange rates at its plant in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of December 31, 2007 we had $10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2007, annualized interest expense on variable rate long-term debt and pre-tax earnings would change by approximately $104,000.

We have not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

The plastics companies are exposed to market risk related to changes in commodity prices for PVC resins, the raw material used to manufacture PVC pipe. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower. Gross margins also decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2007 the electric utility had recognized, on a pretax basis, $632,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value the electric utility's forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. Of the forward energy sales contracts that are marked to market as of December 31, 2007, 97.6% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $56,000 in unrealized gains recognized on the open sales contracts.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. With the advent of the MISO Day 2 market in April 2005, we made several changes to our energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, we implemented a Value at Risk (VaR) limit to further manage market price risk. Exposure to price risk on any open positions as of December 31, 2007 was not material.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity on our consolidated balance sheet as of December 31, 2007 and the change in our consolidated balance sheet position from December 31, 2006 to December 31, 2007:

(in thousands)	December 31, 2007
Current Asset – Marked-to-Market Gain	$ 5,210
Regulatory Asset – Deferred Marked-to-Market Loss	771
Total Assets	5,981
Current Liability – Marked-to-Market Loss	(5,078)
Regulatory Liability – Deferred Marked-to-Market Gain	(271)
Total Liabilities	(5,349)
Net Fair Value of Marked-to-Market Energy Contracts	$ 632

(in thousands)	Year ended December 31, 2007
Fair Value at Beginning of Year	$ 203
Amount Realized on Contracts Entered into in 2006 and Settled in 2007	(203)
Changes in Fair Value of Contracts Entered into in 2006	—
Net Fair Value of Contracts Entered into in 2006 at Year End 2007	—
Changes in Fair Value of Contracts Entered into in 2007	632
Net Fair Value at End of Year	$ 632

The $632,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market on December 31, 2007 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2008	4th Quarter 2008	Total
Net Gain	$118	$514	$632

We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty's financial strength. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2007 was $0.5 million. As of December 31, 2007 we had a net credit risk exposure of $1.5 million from eight counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. We had no exposure at December 31, 2007 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

The $1.5 million credit risk exposure includes net amounts due to the electric utility on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2007. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

IPH has market risk associated with the price of fuel oil and natural gas used in its potato dehydration process as IPH may not be able to increase prices for its finished products to recover increases in fuel costs. In the third quarter of 2006, IPH entered into forward natural gas contracts on the New York Mercantile Exchange market to hedge its exposure to fluctuations in natural gas prices related to approximately 50% of its anticipated natural gas needs through March 2007 for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts were derivatives subject to mark-to-market accounting but they did not qualify for hedge accounting treatment. IPH includes net changes in the market values of these forward contracts in net income as components of cost of goods sold in the period of recognition. Of the $371,000 in unrealized marked-to-market losses on forward natural gas contracts IPH had outstanding on December 31, 2006, $62,000 was reversed and $309,000 was realized on settlement in the first quarter of 2007.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

Our significant accounting policies are described in note 1 to consolidated financial statements. The discussion and analysis of the financial statements and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, valuation of forward energy contracts, unbilled electric revenues, MISO electric market residual load adjustments, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. The following critical accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements.

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses for our electric utility and corporate employees are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. Further discussion of our pension and postretirement benefit plans and related assumptions is included in note 12 to consolidated financial statements.

These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 40 or more years. These benefits can be paid out for up to 40 or more years after an employee retires. Estimates of liabilities and expenses related to these benefits are among our most critical accounting estimates. Although deferral and amortization of fluctuations in actuarially determined benefit obligations and expenses are provided for when actual results on a year-to-year basis deviate from long-range assumptions, compensation increases and healthcare cost increases or a reduction in the discount rate applied from one year to the next can significantly increase our benefit expenses in the year of the change. Also, a reduction in the expected rate of return on pension plan assets in our funded pension plan or realized rates of return on plan assets that are well below assumed rates of return could result in significant increases in recognized pension benefit expenses in the year of the change or for many years thereafter because actuarial losses can be amortized over the average remaining service lives of active employees.

The pension benefit cost for 2008 for our noncontributory funded pension plan is expected to be $3.3 million compared to $4.5 million in 2007. The estimated discount rate used to determine annual benefit cost accruals will be 6.25% in 2008; the discount rate used in 2007 was 6.00%. In selecting the discount rate, we consider the yields of fixed income debt securities, which have ratings of “Aa” published by recognized rating agencies, along with bond matching models specific to our plans as a basis to determine the rate.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates or increases or decreases in the discount rate or rate of increase in future compensation levels could significantly change projected costs. For 2007, all other factors being held constant: a 0.25 increase (or decrease) in the discount rate would have decreased (or increased) our 2007 pension benefit cost by $600,000; a 0.25 increase (or decrease) in the assumed rate of increase in future compensation levels would have increased (or decreased) our 2007 pension benefit cost by $540,000; a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2007 pension benefit cost by $380,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase (or decrease) in the discount rate would have decreased (or increased) our 2007 postretirement medical benefit costs by $70,000. See note 12 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

We believe the estimates made for our pension and other postretirement benefits are reasonable based on the information that is known at the point in time the estimates are made. These estimates and assumptions are subject to a number of variables and are subject to change.

REVENUE RECOGNITION

Our construction companies and two of our manufacturing companies record operating revenues on a percentage-of-completion basis for fixed-price construction contracts. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at our wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. The duration of the majority of these contracts is less than a year. Revenues recognized on jobs in progress as of December 31, 2007 were $325 million. Any expected losses on jobs in progress at year-end 2007 have been recognized. We believe the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

Our electric utility’s forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under accounting principles generally accepted in the United States. The market prices used to value the electric utility’s forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility’s power services’ personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service, and, as such, are estimates. Of the forward energy sales contracts that are marked to market as of December 31, 2007, 97.6% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $56,000 in unrealized gains recognized on the open sales contracts. All of the forward energy contracts for the purchase and sale of electricity marked to market as of December 31, 2007 are scheduled for settlement prior to December 1, 2008.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Our operating companies encounter risks associated with sales and the collection of the associated accounts receivable. As such, they record provisions for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, the operating companies primarily utilize historical rates of accounts receivables written off as a percentage of total revenue. This historical rate is applied to the current revenues on a monthly basis. The historical rate is updated periodically based on events that may change the rate, such as a significant increase or decrease in collection performance and timing of payments as well as the calculated total exposure in relation to the allowance. Periodically, operating companies compare identified credit risks with allowances that have been established using historical experience and adjust allowances accordingly. In circumstances where an operating company is aware of a specific customer’s inability to meet financial obligations, the operating company records a specific allowance for bad debts to reduce the net recognized receivable to the amount it reasonably believes will be collected.

We believe the accounting estimates related to the allowance for doubtful accounts is critical because the underlying assumptions used for the allowance can change from period to period and could potentially cause a material impact to the income statement and working capital.

During 2007, $2.2 million of bad debt expense (0.18% of total 2007 revenue of $1.2 billion) was recorded and the allowance for doubtful accounts was $3.8 million (2.5% of trade accounts receivable) as of December 31, 2007. General economic conditions and specific geographic concerns are major factors that may affect the adequacy of the allowance and may result in a change in the annual bad debt expense. An increase or decrease in our consolidated allowance for doubtful accounts based on one percentage point of outstanding trade receivables at December 31, 2007 would result in a $1.6 million increase or decrease in bad debt expense.

Although an estimated allowance for doubtful accounts on our operating companies’ accounts receivable is provided for, the allowance for doubtful accounts on the electric segment’s wholesale electric sales is insignificant in proportion to annual revenues from these sales. The electric segment has not experienced a bad debt related to wholesale electric sales largely due to stringent risk management criteria related to these sales. Nonpayment on a single wholesale electric sale could result in a significant bad debt expense.

DEPRECIATION EXPENSE AND DEPRECIABLE LIVES

The provisions for depreciation of electric utility property for financial reporting purposes are made on the straight-line method based on the estimated service lives (5 to 65 years) of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.78% in 2007, 2.82% in 2006 and 2.74% in 2005. Depreciation rates on electric utility property are subject to annual regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

Property and equipment of our nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination accounted for under the purchase method of accounting and are depreciated on a straight-line basis over useful lives (3 to 40 years) of the related assets. We believe the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries in which our nonelectric companies operate or innovations in technology could result in a reduction of the estimated useful lives of our nonelectric operating companies’ property, plant and equipment or in an impairment write-down of the carrying value of these properties.

TAXATION

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2007 reflects the most likely probable expected outcome of these tax matters in accordance with FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*, and Statement of Financial Accounting Standards (SFAS) Standards (SFAS) No. 109, *Accounting for Income Taxes*, the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

Deferred income taxes are provided for revenue and expenses which are recognized in different periods for income tax and financial reporting purposes. We assess our deferred tax assets for recoverability based on both historical and anticipated earnings levels. We have not recorded a valuation allowance related to the probability of recovery of our deferred tax assets as we believe reductions in tax payments related to these assets will be fully realized in the future.

ASSET IMPAIRMENT

We are required to test for asset impairment relating to property and equipment whenever events or changes in circumstances indicate that the carrying value of an asset might not be recoverable. We apply SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, in order to determine whether or not an asset is impaired. This standard requires an impairment analysis when indicators of impairment are present. If such indicators are present, the standard requires that if the sum of the future expected cash flows from a company's asset, undiscounted and without interest charges, is less than the carrying value, an asset impairment must be recognized in the financial statements. The amount of the impairment is the difference between the fair value of the asset and the carrying value of the asset.

We believe the accounting estimates related to an asset impairment are critical because they are highly susceptible to change from period to period reflecting changing business cycles and require management to make assumptions about future cash flows over future years and the impact of recognizing an impairment could have a significant effect on operations. Management's assumptions about future cash flows require significant judgment because actual operating levels have fluctuated in the past and are expected to continue to do so in the future.

As of December 31, 2007 an assessment of the carrying values of our long-lived assets and other intangibles indicated that these assets were not impaired.

GOODWILL IMPAIRMENT

Goodwill is required to be evaluated annually for impairment, according to SFAS No. 142, *Goodwill and Other Intangible Assets*. The standard requires a two-step process be performed to analyze whether or not goodwill has been impaired. Step one is to test for potential impairment and requires that the fair value of the reporting unit be compared to its book value including goodwill. If the fair value is higher than the book value, no impairment is recognized. If the fair value is lower than the book value, a second step must be performed. The second step is to measure the amount of impairment loss, if any, and requires that a hypothetical purchase price allocation be done to determine the implied fair value of goodwill. This fair value is then compared to the carrying value of goodwill. If the implied fair value is lower than the carrying value, an impairment must be recorded.

We believe accounting estimates related to goodwill impairment are critical because the underlying assumptions used for the discounted cash flow can change from period to period and could potentially cause a material impact to the income statement. Management's assumptions about inflation rates and other internal and external economic conditions, such as earnings growth rate, require significant judgment based on fluctuating rates and expected revenues. Additionally, SFAS No. 142 requires goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

We evaluate goodwill for impairment on an annual basis and as conditions warrant. As of December 31, 2007 an assessment of the carrying values of our goodwill indicated no impairment.

PURCHASE ACCOUNTING

Through December 31, 2008, under SFAS No. 141, *Business Combinations*, we will account for our acquisitions under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed are recorded at their respective fair values. The excess of purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The recorded values of assets and liabilities are based on third party estimates and valuations when available. The remaining values are based on management's judgments and estimates, and, accordingly, our consolidated financial position or results of operations may be affected by changes in estimates and judgments.

Acquired assets and liabilities assumed that are subject to critical estimates include property, plant and equipment and intangible assets.

The fair value of property, plant and equipment is based on valuations performed by qualified internal personnel and/or outside appraisers. Fair values assigned to plant and equipment are based on several factors including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase.

Intangible assets are identified and valued using the guidelines of SFAS No. 141. The fair value of intangible assets is based on estimates including royalty rates, customer attrition rates and estimated cash flows.

While the allocation of purchase price is subject to a high degree of judgment and uncertainty, we do not expect the estimates to vary significantly once an acquisition is complete. We believe our estimates have been reasonable in the past as there have been no significant valuation adjustments to the final allocation of purchase price.

Beginning in 2009, we will account for acquisitions under the requirements of SFAS No. 141 (revised 2007), *Businesses Combinations*, issued in December 2007. SFAS No. 141(R) replaces the term "purchase method of accounting" with "acquisition method of accounting" and requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values.

KEY ACCOUNTING PRONOUNCEMENTS

SFAS No. 123(R) (revised 2004), *Share-Based Payment,* issued in December 2004, is a revision of SFAS No. 123, *Accounting for Stock-based Compensation,* and supersedes Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*. Beginning in January 2006, we adopted SFAS No. 123(R) on a modified prospective basis. We are required to record stock-based compensation as an expense on our income statement over the period earned based on the fair value of the stock or options awarded on their grant date. The application of SFAS No. 123(R) reporting requirements resulted in recording incremental after-tax compensation expense in 2006 as follows:

- $163,000, net-of-tax, for non-vested stock options that were outstanding on December 31, 2005.
- $235,000 for the 15% discount offered under our Employee Stock Purchase Plan.

See note 7 to consolidated financial statement for additional discussion. For years prior to 2006, we reported our stock-based compensation under the requirements of APB No. 25 and furnished related pro forma footnote information required under SFAS No. 123.

In November 2005, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 123(R)-3, *Transition Election Related to Accounting for Tax Effects of Share-Based Payment Awards.* We elected to adopt the alternative transition method provided in FSP No. FAS 123(R)-3 for calculating the tax effects of stock-based compensation. The alternative transition method includes simplified methods to determine the beginning balance of the additional paid-in capital (APIC) pool related to the tax effects of stock-based compensation, and to determine the subsequent impact on the APIC pool and the statement of cash flows of the tax effects of stock-based awards that were fully vested and outstanding upon the adoption of SFAS No. 123(R).

FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109,* was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes*. We adopted FIN No. 48 on January 1, 2007 and have recognized, in our consolidated financial statements, the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. Only tax positions that meet the "more-likely-than-not" threshold on the reporting date may be recognized. See additional discussion under Income Taxes in note 15 to the consolidated financial statements that follow.

SFAS No. 157, *Fair Value Measurements,* was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. Other than additional footnote disclosures related to the use of fair value measurements in the areas of derivatives, goodwill and asset impairment evaluations and financial instruments, we do not expect the adoption of SFAS No. 157 to have a significant impact on our consolidated balance sheet, income statement or statement of cash flows.

SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* was issued by the FASB in September 2006. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 will not change the amount of net periodic benefit expense recognized in an entity's income statement. It is effective for fiscal years ending after December 15, 2006. We determined the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, we charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* rather than to Accumulated Other Comprehensive Loss in equity as prescribed by SFAS No. 158. Application of this standard had the following effects on our December 31, 2006 consolidated balance sheet:

(in thousands)	2006
Decrease in Executive Survivor and Supplemental Retirement Plan Intangible Asset	$ (767)
Increase in Regulatory Assets (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are subject to recovery through electric rates)	36,736
Increase in Pension Benefit and Other Postretirement Liability	(34,714)
Increase in Deferred Tax Liability	(502)
Decrease in Accumulated Other Comprehensive Loss (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are not subject to recovery through electric rates) (increase to equity)	(753)

The adoption of this standard did not affect compliance with debt covenants maintained in our financing agreements.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115,* was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. As of December 31, 2007 we had not opted, nor do we currently plan to opt, to apply fair value accounting to any financial instruments or other items that we are not currently required to account for at fair value.

SFAS No. 141(R), *Businesses Combinations,* was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008—January 1, 2009 for Otter Tail Corporation. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141's guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

Management's Report Regarding Internal Controls Over Financial Reporting

Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this annual report. The consolidated financial statements of Otter Tail Corporation (the Company) have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

In order to assure the consolidated financial statements are prepared in conformance with generally accepted accounting principles, management is responsible for establishing and maintaining adequate internal controls over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). These internal controls are designed only to provide reasonable assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and assets are safeguarded against loss from unauthorized use or disposition.

Management has completed its assessment of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework* to conduct the required assessment of the effectiveness of the Company's internal controls over financial reporting.

There have not been any changes in the Company's internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15 (f) and 15d-15(f)) during the fiscal year to which this report relates that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Based on this assessment, we believe that, as of December 31, 2007 the Company's internal controls over financial reporting are effective based on those criteria.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, audited the Company's consolidated financial statements included in this annual report and issued an attestation report on the Company's internal controls over financial reporting.

/s/ John Erickson

John Erickson
President and Chief Executive Officer

/s/ Kevin Moug

Kevin Moug
Chief Financial Officer and Treasurer

February 20, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE SHAREHOLDERS OF OTTER TAIL CORPORATION

We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and its subsidiaries (the “Company”) as of December 31, 2007 and 2006, and the related consolidated statements of income, common shareholders’ equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. We also have audited the Company’s internal control over financial reporting as of December 31, 2007 based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report Regarding Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company’s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in note 1 to the consolidated financial statements, effective December 31, 2006, the Corporation adopted the recognition and disclosure provisions of Statement of Financial Accounting Standards No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans.”

/s/ Deloitte & Touche LLP

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 20, 2008

Otter Tail Corporation

Consolidated Statements of Income—For the Years Ended December 31

(in thousands, except per-share amounts)	**2007**	2006	2005
Operating Revenues			
Electric	**$ 323,158**	$ 305,703	$312,624
Nonelectric	**915,729**	799,251	669,245
Total Operating Revenues	**1,238,887**	1,104,954	981,869
Operating Expenses			
Production Fuel — Electric	**60,482**	58,729	55,927
Purchased Power — Electric System Use	**74,690**	58,281	58,828
Electric Operation and Maintenance Expenses	**107,041**	103,548	99,904
Cost of Goods Sold — Nonelectric (excludes depreciation; included below)	**712,547**	611,737	502,407
Other Nonelectric Expenses	**121,110**	115,290	109,707
Depreciation and Amortization	**52,830**	49,983	46,458
Property Taxes — Electric	**9,413**	9,589	10,043
Total Operating Expenses	**1,138,113**	1,007,157	883,274
Operating Income	**100,774**	97,797	98,595
Other Income and Deductions	**2,012**	(440)	1,773
Interest Charges	**20,857**	19,501	18,459
Income from Continuing Operations Before Income Taxes	**81,929**	77,856	81,909
Income Taxes — Continuing Operations	**27,968**	27,106	28,007
Net Income from Continuing Operations	**53,961**	50,750	53,902
Discontinued Operations			
Income (Loss) from Discontinued Operations Net of Taxes of $28 in 2006 and ($261) in 2005	**—**	26	(352)
Goodwill Impairment Loss	**—**	—	(1,003)
Gain on Disposition of Discontinued Operations Net of Taxes of $224 in 2006 and $5,831 in 2005	**—**	336	10,004
Net Income from Discontinued Operations	**—**	362	8,649
Net Income	**53,961**	51,112	62,551
Preferred Dividend Requirements	**736**	736	735
Earnings Available for Common Shares	**$ 53,225**	$ 50,376	$ 61,816
Average Number of Common Shares Outstanding—Basic	**29,681**	29,394	29,223
Average Number of Common Shares Outstanding—Diluted	**29,970**	29,664	29,348
Basic Earnings Per Share:			
Continuing Operations (net of preferred dividend requirements)	**$ 1.79**	$ 1.70	$ 1.82
Discontinued Operations	**—**	0.01	0.30
	$ 1.79	$ 1.71	$ 2.12
Diluted Earnings Per Share:			
Continuing Operations (net of preferred dividend requirements)	**$ 1.78**	$ 1.69	$ 1.81
Discontinued Operations	**—**	0.01	0.30
	$ 1.78	$ 1.70	$ 2.11
Dividends Per Common Share	**$ 1.17**	$ 1.15	$ 1.12

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Balance Sheets, December 31

(in thousands)	2007	2006
Assets		
Current Assets		
Cash and Cash Equivalents	**$ 39,824**	$ 6,791
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $3,811 for 2007 and $2,964 for 2006)	**151,446**	135,011
Other	**14,934**	10,265
Inventories	**97,214**	103,002
Deferred Income Taxes	**7,200**	8,069
Accrued Utility and Cost-of-Energy Revenues	**32,501**	23,931
Costs and Estimated Earnings in Excess of Billings	**42,234**	38,384
Other	**15,299**	9,611
Assets of Discontinued Operations	**—**	289
Total Current Assets	**400,652**	335,353
Investments	**10,057**	8,955
Other Assets	**24,500**	20,991
Goodwill	**99,242**	98,110
Other Intangibles—Net	**20,456**	20,080
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	**6,986**	6,133
Regulatory Assets and Other Deferred Debits	**38,837**	50,419
Total Deferred Debits	**45,823**	56,552
Plant		
Electric Plant in Service	**1,028,917**	930,689
Nonelectric Operations	**257,590**	239,269
Total	**1,286,507**	1,169,958
Less Accumulated Depreciation and Amortization	**506,744**	479,557
Plant—Net of Accumulated Depreciation and Amortization	**779,763**	690,401
Construction Work in Progress	**74,261**	28,208
Net Plant	**854,024**	718,609
Total	**$1,454,754**	$1,258,650

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Balance Sheets, December 31

(in thousands, except share data)	**2007**	2006
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	**$ 95,000**	$ 38,900
Current Maturities of Long-Term Debt	**3,004**	3,125
Accounts Payable	**141,390**	120,195
Accrued Salaries and Wages	**29,283**	28,653
Accrued Federal and State Income Taxes	**—**	2,383
Other Accrued Taxes	**11,409**	11,509
Other Accrued Liabilities	**13,873**	10,495
Liabilities of Discontinued Operations	**—**	197
Total Current Liabilities	**293,959**	215,457
Pensions Benefit Liability	**39,429**	44,035
Other Postretirement Benefits Liability	**30,488**	32,254
Other Noncurrent Liabilities	**23,228**	18,866
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	**105,813**	112,740
Deferred Tax Credits	**16,761**	8,181
Regulatory Liabilities	**62,705**	63,875
Other	**275**	281
Total Deferred Credits	**185,554**	185,077
Capitalization (page 42)		
Long-Term Debt, Net of Current Maturities	**342,694**	255,436
Class B Stock Options of Subsidiary	**1,255**	1,255
Cumulative Preferred Shares	**15,500**	15,500
Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2007—29,849,789 Shares; 2006—29,521,770 Shares	**149,249**	147,609
Premium on Common Shares	**108,885**	99,223
Retained Earnings	**263,332**	245,005
Accumulated Other Comprehensive Income (Loss)	**1,181**	(1,067)
Total Common Equity	**522,647**	490,770
Total Capitalization	**882,096**	762,961
Total	**$1,454,754**	$1,258,650

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Statements of Common Shareholders' Equity and Comprehensive Income

(in thousands, except common shares outstanding)	Common Shares Outstanding	Par Value, Common Shares	Premium on Common Shares	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Equity
Balance, December 31, 2004	**28,976,919**	**$144,885**	**$ 87,865**	**$(2,577)**	**$199,427**	**$ (390)**	**$429,210**
Common Stock Issuances, Net of Expenses	456,211	2,281	8,483	(529)			10,235
Common Stock Retirements	(31,907)	(160)	(756)				(916)
Amortization of Unearned Compensation—Stock Awards				1,386			1,386
Comprehensive Income:							
Net Income					62,551		62,551
Unrealized Loss on Marketable Equity Securities (net-of-tax)						(23)	(23)
Foreign Currency Exchange Translation (net-of-tax)						437	437
SFAS No. 87 Minimum Pension Liability Adjustment (net-of-tax)						(6,163)	(6,163)
Total Comprehensive Income							56,802
Tax Benefit for Exercise of Stock Options			596				596
Stock Incentive Plan Performance Award Accrual			943				943
Premium on Purchase of Stock for Employee Purchase Plan			(363)				(363)
Cumulative Preferred Dividends					(735)		(735)
Common Dividends					(32,728)		(32,728)
Balance, December 31, 2005	**29,401,223**	**$147,006**	**$ 96,768**	**$(1,720)**	**$228,515**	**$ (6,139)**	**$464,430**
Common Stock Issuances, Net of Expenses	136,917	685	1,837				2,522
Common Stock Retirements	(16,370)	(82)	(378)				(460)
SFAS No. 123(R) Reclassifications (note 7)			(2,490)	1,720			(770)
Comprehensive Income:							
Net Income					51,112		51,112
Unrealized Gain on Marketable Equity Securities (net-of-tax)						56	56
Foreign Currency Exchange Translation (net-of-tax)						6	6
SFAS No. 87 Minimum Pension Liability Adjustment (net-of-tax)						4,257	4,257
Total Comprehensive Income							55,431
SFAS No. 158 Items (net-of-tax) Reversal of 12/31/06 Minimum Pension Liability Balance						3,296	3,296
Unrecognized Postretirement Benefit Costs						(24,585)	(24,585)
Unrecognized Costs Classified as Regulatory Assets						22,042	22,042
Tax Benefit for Exercise of Stock Options			288				288
Stock Incentive Plan Performance Award Accrual			2,404				2,404
Vesting of Restricted Stock Granted to Employees			1,096				1,096
Premium on Purchase of Stock for Employee Purchase Plan			(302)				(302)
Cumulative Preferred Dividends					(736)		(736)
Common Dividends					(33,886)		(33,886)
Balance, December 31, 2006	**29,521,770**	**$147,609**	**$ 99,223**	**$ —**	**$245,005**	**$(1,067)(a)**	**$490,770**
Common Stock Issuances, Net of Expenses	336,508	1,683	6,018				7,701

Common Stock Retirements	(8,489)	(43)	(252)				(295)
Comprehensive Income:							
Net Income					53,961		53,961
Unrealized Gain on Marketable Equity Securities (net-of-tax)						4	4
Foreign Currency Exchange Translation (net-of-tax)						2,019	2,019
SFAS No. 158 Items (net-of-tax):							
Amortization of Unrecognized Postretirement Benefit Costs						165	165
Actuarial Gains and Regulatory Allocations Adjustments						60	60
Total Comprehensive Income							56,209
Tax Benefit for Exercise of Stock Options			1,092				1,092
Stock Incentive Plan Performance Award Accrual			2,213				2,213
Vesting of Restricted Stock Granted to Employees			860				860
Premium on Purchase of Stock for Employee Purchase Plan			(269)				(269)
Cumulative Effect of Adoption of FIN No. 48					(118)		(118)
Cumulative Preferred Dividends					(736)		(736)
Common Dividends					(34,780)		(34,780)
Balance, December 31, 2007	**29,849,789**	**$149,249**	**$108,885**	**$ —**	**$263,332**	**$ 1,181(a)**	**$522,647**

(a) Accumulated Other Comprehensive Income (Loss) on December 31 is comprised of the following:

2006 *(in thousands)*	Before Tax	Tax Effect	Net-of-Tax
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (4,238)	$ 1,695	$ (2,543)
Foreign Currency Exchange Translation	2,430	(972)	1,458
Unrealized Gain on Marketable Equity Securities	30	(12)	18
Net Accumulated Other Comprehensive Loss	$ (1,778)	$ 711	$ (1,067)

2007 *(in thousands)*	Before Tax	Tax Effect	Net-of-Tax
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (3,863)	$ 1,545	$ (2,318)
Foreign Currency Exchange Translation	5,795	(2,318)	3,477
Unrealized Gain on Marketable Equity Securities	36	(14)	22
Net Accumulated Other Comprehensive Income	$ 1,968	$ (787)	$ 1,181

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Statements of Cash Flows—For the Years Ended December 31

(in thousands)	**2007**	2006	2005
Cash Flows from Operating Activities			
Net Income	**$ 53,961**	$ 51,112	$ 62,551
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Net Gain on Sale of Discontinued Operations	**—**	(336)	(10,004)
(Income) Loss from Discontinued Operations	**—**	(26)	1,355
Depreciation and Amortization	**52,830**	49,983	46,458
Deferred Tax Credits	**(1,169)**	(1,146)	(1,150)
Deferred Income Taxes	**4,366**	(1,258)	(9,223)
Change in Deferred Debits and Other Assets	**6,505**	(38,499)	8,865
Discretionary Contribution to Pension Plan	**(4,000)**	(4,000)	(4,000)
Change in Noncurrent Liabilities and Deferred Credits	**481**	45,340	1,321
Allowance for Equity (Other) Funds Used During Construction	**—**	2,529	(723)
Change in Derivatives Net of Regulatory Deferral	**(800)**	3,083	(2,615)
Stock Compensation Expense	**2,986**	2,404	2,388
Other—Net	**(1,837)**	418	1,118
Cash (Used for) Provided by Current Assets and Current Liabilities:			
Change in Receivables	**(18,903)**	(15,713)	(9,715)
Change in Inventories	**8,407**	(14,345)	(12,500)
Change in Other Current Assets	**(14,616)**	(17,409)	(13,908)
Change in Payables and Other Current Liabilities	**(2,556)**	23,022	32,682
Change in Interest and Income Taxes Payable	**(843)**	(5,952)	(2,552)
Net Cash Provided by Continuing Operations	**84,812**	79,207	90,348
Net Cash Provided by Discontinued Operations	**—**	1,039	5,452
Net Cash Provided by Operating Activities	**84,812**	80,246	95,800
Cash Flows from Investing Activities			
Capital Expenditures	**(161,985)**	(69,448)	(59,969)
Proceeds from Disposal of Noncurrent Assets	**12,486**	5,233	4,193
Acquisitions—Net of Cash Acquired	**(6,750)**	—	(11,223)
(Increases) Decreases in Other Investments	**(7,745)**	(3,326)	4,171
Net Cash Used in Investing Activities — Continuing Operations	**(163,994)**	(67,541)	(62,828)
Net Proceeds from Sale of Discontinued Operations	**—**	1,960	34,185
Net Cash Provided by Investing Activities — Discontinued Operations	**—**	—	602
Net Cash Used in Investing Activities	**(163,994)**	(65,581)	(28,041)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	**—**	(11)	(3,329)
Net Short-Term Borrowings (Repayments)	**56,100**	22,900	(23,950)
Proceeds from Issuance of Common Stock, Net of Issuance Expenses	**7,733**	2,444	9,690
Payments for Retirement of Common Stock and Class B Stock of Subsidiary	**(305)**	(463)	(939)
Proceeds from Issuance of Long-Term Debt	**205,129**	149	368
Debt Issuance Expenses	**(1,762)**	(458)	(140)
Payments for Retirement of Long-Term Debt	**(118,171)**	(3,287)	(7,232)
Dividends Paid	**(35,516)**	(34,621)	(33,463)
Net Cash Provided by (Used in) Financing Activities — Continuing Operations	**113,208**	(13,347)	(58,995)
Net Cash Used in Financing Activities — Discontinued Operations	**—**	—	(2,996)
Net Cash Provided by (Used in) Financing Activities	**113,208**	(13,347)	(61,991)
Effect of Foreign Exchange Rate Fluctuations on Cash	**(993)**	43	(338)
Net Change in Cash and Cash Equivalents	**33,033**	1,361	5,430
Cash and Cash Equivalents at Beginning of Year — Continuing Operations	**6,791**	5,430	—
Cash and Cash Equivalents at End of Year — Continuing Operations	**$ 39,824**	$ 6,791	$ 5,430

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Statements of Capitalization, December 31

(in thousands, except share data)		**2007**	2006
Long-Term Debt			
Senior Unsecured Notes 6.63%, due December 1, 2011		**$ 90,000**	$ 90,000
Senior Debentures 6.375%, due December 1, 2007		**—**	50,000
Senior Unsecured Note 5.778%, due November 30, 2017		**50,000**	—
Insured Senior Notes 5.625%, due October 1, 2017 (retired October 15, 2007)		**—**	40,000
Senior Notes 6.80%, due October 1, 2032 (retired October 15, 2007)		**—**	25,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037		**50,000**	—
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027		**42,000**	—
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017		**33,000**	—
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022		**30,000**	—
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022		**20,705**	20,735
Pollution Control Refunding Revenue Bonds, Variable, 3.97% at December 31, 2007, due December 1, 2012		**10,400**	10,400
Lombard US Equipment Finance Note 6.76%, due October 2, 2010		**6,986**	9,314
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017		**5,185**	5,185
Obligations of Varistar Corporation — Various up to 8.25% at December 31, 2007		**7,891**	8,424
Total		**346,167**	259,058
Less:			
Current Maturities		**3,004**	3,125
Unamortized Debt Discount		**469**	497
Total Long-Term Debt		**342,694**	255,436
Class B Stock Options of Subsidiary		**1,255**	1,255
Cumulative Preferred Shares—Without Par Value (Stated and Liquidating Value $100 a Share)—Authorized 1,500,000 Shares; nonvoting and redeemable at the option of the Company			
Series Outstanding:	Call Price December 31, 2007		
$3.60, 60,000 Shares	$ 102.25	**6,000**	6,000
$4.40, 25,000 Shares	$ 102.00	**2,500**	2,500
$4.65, 30,000 Shares	$ 101.50	**3,000**	3,000
$6.75, 40,000 Shares	$102.025	**4,000**	4,000
Total Preferred		**15,500**	15,500
Cumulative Preference Shares—Without Par Value, Authorized 1,000,000 Shares; Outstanding: None			
Total Common Shareholders' Equity		**522,647**	490,770
Total Capitalization		**$882,096**	$762,961

See accompanying notes to consolidated financial statements.

1. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements of Otter Tail Corporation and its wholly-owned subsidiaries (the Company) include the accounts of the following segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. See note 2 to the consolidated financial statements for further descriptions of the Company's business segments. All significant intercompany balances and transactions have been eliminated in consolidation except profits on sales to the regulated electric utility company from nonregulated affiliates, which is in accordance with the requirements of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. Such amounts are not material.

Regulation and Statement of Financial Accounting Standards No. 71

As a regulated entity, the Company and the electric utility account for the financial effects of regulation in accordance with SFAS No. 71. This statement allows for the recording of a regulatory asset or liability for costs that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, the Company defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 4 for further discussion.

The Company's regulated electric utility business is subject to various state and federal agency regulations. The accounting policies followed by this business are subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's nonelectric businesses.

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $2,276,000 in 2007, $202,000 in 2006 and $190,000 in 2005. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated service lives of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.78% in 2007, 2.82% in 2006 and 2.74% in 2005. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination accounted for under the purchase method of accounting, and are depreciated on a straight-line basis over the assets' estimated useful lives (3 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. The amount of interest capitalized on nonelectric plant was $390,000 in 2007, $31,000 in 2006 and none in 2005. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

Jointly Owned Plants

The consolidated balance sheets include the Company's ownership interests in the assets and liabilities of Big Stone Plant (53.9%) and Coyote Station (35.0%). The following amounts are included in the December 31, 2007 and 2006 consolidated balance sheets:

(in thousands)	Big Stone Plant	Coyote Station
December 31, 2007		
Electric Plant in Service	$ 136,493	$ 147,724
Accumulated Depreciation	(72,342)	(83,417)
Net Plant	$ 64,151	$ 64,307
December 31, 2006		
Electric Plant in Service	$ 124,965	$ 147,319
Accumulated Depreciation	(75,872)	(80,336)
Net Plant	$ 49,093	$ 66,983

The Company's share of direct revenue and expenses of the jointly owned plants is included in operating revenue and expenses in the consolidated statements of income.

Recoverability of Long-Lived Assets
The Company reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. The Company determines potential impairment by comparing the carrying value of the assets with net cash flows expected to be provided by operating activities of the business or related assets. If the sum of the expected future net cash flows is less than the carrying values, the Company would determine whether an impairment loss should be recognized. An impairment loss would be quantified by comparing the amount by which the carrying value exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

Income Taxes
Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes tax credits over the estimated lives of related property. Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109*, was issued in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes*. The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its consolidated financial statements, the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%.

Revenue Recognition
Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as the electric utility's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

For the Company's operating companies recognizing revenue on certain products when shipped, those operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

Electric customers' meters are read and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment (FCA)—under which the rates are adjusted to reflect changes in average cost of fuels and purchased power—and a surcharge for recovery of conservation-related expenses. Revenue is accrued for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the FCA.

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered.

The Company's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on the Company's consolidated statement of income. Under SFAS No. 133 as amended and interpreted, the Company's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. The Company is required to mark to market these forward energy contracts and recognize changes in the fair value of these contracts as components of income over the life of the contracts. See note 5 for further discussion.

Plastics operating revenues are recorded when the product is shipped.

Manufacturing operating revenues are recorded when products are shipped and on a percentage-of-completion basis for construction type contracts.

Health Services operating revenues on major equipment and installation contracts are recorded when the equipment is delivered or when installation is completed and accepted. Amounts received in advance under customer service contracts are deferred and recognized on a straight-line basis over the contract period. Revenues generated in the imaging operations are recorded on a fee-per-scan basis when the scan is performed.

Food Ingredient Processing revenues are recorded when the product is shipped.

Other Business Operations operating revenues are recorded when services are rendered or products are shipped. In the case of construction contracts, the percentage-of-completion method is used.

Some of the operating businesses enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The Company's consolidated revenues recorded under the percentage-of-completion method were 30.1% in 2007, 25.1% in 2006 and 17.9% in 2005. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company's wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized. The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	December 31, 2007	December 31, 2006
Costs Incurred on Uncompleted Contracts	$ 286,358	$ 257,370
Less Billings to Date	(292,692)	(284,273)
Plus Estimated Earnings Recognized	38,275	35,955
	$ 31,941	$ 9,052

The following costs and estimated earnings in excess of billings are included in the Company's consolidated balance sheet. Billings in excess of costs and estimated earnings on uncompleted contracts are included in Accounts Payable.

(in thousands)	December 31, 2007	December 31, 2006
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 42,234	$ 38,384
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(10,293)	(29,332)
	$ 31,941	$ 9,052

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI) were $36,161,000 as of December 31, 2007. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

Foreign Currency Translation

The functional currency for the operations of the Canadian subsidiary of Idaho Pacific Holdings, Inc. (IPH) is the Canadian dollar. This subsidiary realizes foreign currency transaction gains or losses on settlement of receivables related to its sales, which are mostly in U.S. dollars, and on exchanging U.S. currency for Canadian currency for its Canadian operations. This subsidiary recorded foreign currency transaction losses of $656,000 ($393,000 net-of-tax) in U.S. dollars in 2007 as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar in 2007. Transaction gains and losses in 2006 and 2005 were not significant due to the relative stability of the currencies in those years. The translation of Canadian currency into U.S. dollars is performed for balance sheet accounts using exchange rates in effect at the balance sheet dates, except for the common equity accounts which are at historical rates, and for revenue and expense accounts using a weighted average exchange during the year. Gains or losses resulting from the translation are included in Accumulated Other Comprehensive Income (Loss) in the equity section of the Company's consolidated balance sheet.

The functional currency for the Canadian subsidiary of DMI, formed in November 2005, is the U.S. dollar. There are no foreign currency translation gains or losses related to this entity. However, this subsidiary may realize foreign currency transaction gains or losses on settlement of liabilities related to goods or services purchased in Canadian dollars. Foreign currency transaction losses related to balance sheet adjustments of Canadian dollar liabilities to U.S. dollar equivalents and realized losses on settlement of those liabilities were $102,000 ($61,000 net-of-tax) in U.S. dollars in 2007 as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar in 2007.

Shipping and Handling Costs

The Company includes revenues received for shipping and handling in operating revenues. Expenses paid for shipping and handling are recorded as part of cost of goods sold.

Use of Estimates

The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, valuations of forward energy contracts, residual load adjustments related to purchase and sales transactions processed through the Midwest Independent

Transmission System Operator (MISO) that are pending settlement, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash Equivalents

The Company considers all highly liquid debt instruments purchased with maturity of 90 days or less to be cash equivalents.

Supplemental Disclosures of Cash Flow Information

(in thousands)	2007	2006	2005
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$23,514	$ 1,401	$ —
Cash Paid During the Year from Continuing Operations for:			
Interest (net of amount capitalized)	$18,155	$18,456	$17,637
Income Taxes	$25,906	$35,061	$39,548
Cash Paid During the Year from Discontinued Operations for:			
Interest	$ —	$ 91	$ 119
Income Taxes	$ —	$ 423	$ 323

Investments

The following table provides a breakdown of the Company's investments at December 31, 2007 and 2006:

(in thousands)	December 31, 2007	December 31, 2006
Cost Method:		
Economic Development Loan Pools	$ 655	$ 569
Other	1,303	1,518
Equity Method:		
Affordable Housing Partnerships	1,851	2,228
Marketable Securities Classified as Available-for-Sale	6,248	4,640
Total Investments	$ 10,057	$ 8,955

The Company has investments in eleven limited partnerships that invest in tax-credit-qualifying affordable-housing projects that provided tax credits of $285,000 in 2007, $839,000 in 2006 and $1,324,000 in 2005. The Company owns a majority interest in eight of the eleven limited partnerships with a total investment of $1,837,000. FIN No. 46, *Consolidation of Variable Interest Entities*, requires full consolidation of the majority-owned partnerships. However, the Company includes these entities on its consolidated financial statements on an equity method basis due to immateriality. Consolidating these entities would have represented less than 0.5% of total assets, 0.1% of total revenues and (0.3%) of operating income for the Company as of, and for the year ended, December 31, 2007 and would have no impact on the Company's 2007 consolidated net income as the amount is the same under both the equity and full consolidation methods.

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their market values on December 31, 2007. See further discussion under note 13.

Inventories

The Electric segment inventories are reported at average cost. All other segments' inventories are stated at the lower of cost (first-in, first-out) or market. Inventories consist of the following:

(in thousands)	December 31, 2007	December 31, 2006
Finished Goods	$ 38,952	$ 46,477
Work in Process	5,218	5,663
Raw Material, Fuel and Supplies	53,044	50,862
Total Inventories	$ 97,214	$ 103,002

Goodwill and Intangible Assets

The Company accounts for goodwill and other intangible assets in accordance with the requirements of SFAS No. 142, *Goodwill and Other Intangible Assets*, requiring goodwill and indefinite-lived intangible assets to be measured for impairment at least annually and more often when events indicate the assets may be impaired. Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

Changes in the carrying amount of Goodwill by segment are as follows:

(in thousands)	Balance December 31, 2006	Adjustment to Goodwill Acquired in 2004	Goodwill Acquired in 2007	Balance December 31, 2007
Plastics	$ 19,302	$ —	$ —	$ 19,302
Manufacturing	15,698	—	1,048	16,746
Health Services	24,328	—	—	24,328
Food Ingredient Processing	24,240	84	—	24,324
Other Business Operations	14,542	—	—	14,542
Total	$ 98,110	$ 84	$ 1,048	$ 99,242

The following table summarizes components of the Company's intangible assets as of December 31:

2007 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets:			
Covenants Not to Compete	$ 2,637	$ 2,113	$ 524
Customer Relationships	10,879	1,469	9,410
Other Intangible Assets Including Contracts	2,785	1,775	1,010
Total	$ 16,301	$ 5,357	$ 10,944
Nonamortized Intangible Assets:			
Brand/Trade Name	$ 9,512	$ —	$ 9,512

2006 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets:			
Covenants Not to Compete	$ 2,198	$ 1,813	$ 385
Customer Relationships	10,574	1,016	9,558
Other Intangible Assets Including Contracts	2,083	1,291	792
Total	$ 14,855	$ 4,120	$ 10,735
Nonamortized Intangible Assets:			
Brand/Trade Name	$ 9,345	$ —	$ 9,345

Intangible assets with finite lives are being amortized on a straight-line basis over lives that vary from one to 25 years. The amortization expense for these intangible assets was $1,227,000 for 2007, $1,079,000 for 2006 and $1,077,000 for 2005. The estimated annual amortization expense for these intangible assets for the next five years is: $877,000 for 2008, $795,000 for 2009, $623,000 for 2010, $516,000 for 2011 and $507,000 for 2012.

New Accounting Standards

SFAS No. 123(R) (revised 2004), *Share-Based Payment,* issued in December 2004, is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees.* Beginning in January 2006, the Company adopted SFAS No. 123(R) on a modified prospective basis. The Company is required to record stock-based compensation as an expense on its income statement over the period earned based on the fair value of the stock or options awarded on their grant date. The application of SFAS No. 123(R) reporting requirements resulted in recording incremental after-tax compensation expense in 2006 as follows:

- $163,000, net-of-tax, in 2006 for non-vested stock options that were outstanding on December 31, 2005.
- $235,000 in 2006 for the 15% discount offered under the Company's Employee Stock Purchase Plan.

For years prior to 2006, the Company reported its stock-based compensation under the requirements of APB No. 25 and furnished related pro forma footnote information required under SFAS No. 123. See note 7 for additional discussion.

In November 2005, the FASB issued FASB Staff Position (FSP) No. FAS 123(R)-3, *Transition Election Related to Accounting for Tax Effects of Share-Based Payment Awards.* The Company elected to adopt the alternative transition method provided in FSP No. FAS 123(R)-3 for calculating the tax effects of stock-based compensation. The alternative transition method includes simplified methods to determine the beginning balance of the Additional Paid-In Capital (APIC) pool related to the tax effects of stock-based compensation, and to determine the subsequent impact on the APIC pool and the statement of cash flows of the tax effects of stock-based awards that were fully vested and outstanding upon the adoption of SFAS No. 123(R).

FIN No. 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109,* was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes*. The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its consolidated financial statements, the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. Only tax positions that meet the "more-likely-than-not" threshold on the reporting date may be recognized. See note 15 for additional discussion.

SFAS No. 157, *Fair Value Measurements,* was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 will be effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. Other than additional footnote disclosures related to the use of fair value measurements in the areas of derivatives, goodwill and asset impairment evaluations and financial instruments, the Company does not expect the adoption of SFAS No. 157 to have a significant impact on its consolidated balance sheet, income statement or statement of cash flows.

SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* was issued by the FASB in September 2006 and became effective for the Company in 2006. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 did not change the amount of net periodic benefit expense recognized in an entity's income statement. The Company determined the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Loss in equity as prescribed by SFAS No. 158. Application of this standard had the following effects on the Company's December 31, 2006 consolidated balance sheet:

(in thousands)	2006
Decrease in Executive Survivor and Supplemental Retirement Plan Intangible Asset	$ (767)
Increase in Regulatory Assets (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are subject to recovery through electric rates)	36,736
Increase in Pension Benefit and Other Postretirement Liability	(34,714)
Increase in Deferred Tax Liability	(502)
Decrease in Accumulated Other Comprehensive Loss (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are not subject to recovery through electric rates) (increase to equity)	(753)

The adoption of this standard did not affect compliance with debt covenants maintained in the Company's financing agreements.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115,* was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. As of December 31, 2007 the Company had not opted, nor does it currently plan to opt, to apply fair value accounting to any financial instruments or other items that it is not currently required to account for at fair value.

SFAS No. 141 (revised 2007), Businesses Combinations (SFAS No. 141(R)), was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations*, and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008—January 1, 2009 for the Company. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting” with “acquisition method of accounting,” SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141’s cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141’s guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

2. Business Combinations, Dispositions and Segment Information

On February 19, 2007 the Company’s wholly-owned subsidiary, ShoreMaster, Inc. (ShoreMaster), acquired the assets of the Aviva Sports product line for $2.0 million in cash. The Aviva Sports product line operates under Aviva Sports, Inc. (Aviva), a newly-formed wholly-owned subsidiary of ShoreMaster. The Aviva Sports product line is sold internationally and consists of products for consumer use in the pool, lake and yard, as well as commercial use at summer camps, resorts and large public swimming pools. The acquisition of the Aviva Sports product line fits well with the other product lines of ShoreMaster, a leading manufacturer and supplier of waterfront equipment.

On May 15, 2007 the Company’s wholly-owned subsidiary, BTD Manufacturing, Inc. (BTD), acquired the assets of Pro Engineering, LLC (Pro Engineering) for $4.8 million in cash. Pro Engineering specializes in providing metal parts stampings to customers in the Midwest. The acquisition of Pro Engineering by BTD provides expanded growth opportunities for both companies.

Below, are condensed balance sheets, at the dates of the respective business combinations, disclosing the preliminary allocation of the purchase price assigned to each major asset and liability category of Aviva and Pro Engineering:

(in thousands)	Aviva	Pro Engineering
Assets		
Current Assets	$ 2,083	$ 1,956
Goodwill	—	1,048
Other Intangible Assets	870	396
Plant	—	1,600
Total Assets	$ 2,953	$ 5,000
Liabilities		
Current Liabilities	$ 988	$ 215
Noncurrent Liabilities	—	—
Total Liabilities	$ 988	$ 215
Cash Paid	$ 1,965	$ 4,785

Other Intangible Assets related to the Aviva acquisition include $83,000 for a nonamortizable brand name and $787,000 in intangible assets being amortized over various periods up to 15 years. Other Intangible Assets related to the Pro Engineering acquisition include $51,000 for a nonamortizable brand name and $345,000 in intangible assets being amortized over various periods up to 20 years.

The Company acquired no new businesses in 2006.

The Company paid cash of $10.5 million, net of cash acquired, for three businesses purchased in 2005.

All of the acquisitions described above were accounted for using the purchase method of accounting. Disclosure of pro forma information related to the results of operations of the entities acquired in 2007 for the periods presented in this report is not required due to immateriality.

In June 2006, OTESCO, the Company’s energy services company, sold its gas marketing operations. In 2005, the Company sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Prior to disposition, OTESCO’s gas marketing operations and MIS were included in the Other Business Operations segment and SGS and CLC were included in the Manufacturing segment. See note 16 on discontinued operations for further discussion.

Segment Information—The accounting policies of the segments are described under note 1 — Summary of Significant Accounting Policies. The Company's businesses have been classified into six segments based on products and services and reach customers in all 50 states and international markets. The six segments are: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota under the name Otter Tail Power Company (the electric utility). In addition, the electric utility is an active wholesale participant in the MISO markets. The electric utility operations have been the Company's primary business since incorporation. The Company's electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation.

All of the businesses in the following segments are owned by a wholly-owned subsidiary of the Company.

Plastics consists of businesses producing polyvinyl chloride and polyethylene pipe in the Upper Midwest and Southwest regions of the United States.

Manufacturing consists of businesses in the following manufacturing activities: production of waterfront equipment, wind towers, material and handling trays and horticultural containers, contract machining, and metal parts stamping and fabrication. These businesses have manufacturing facilities in Minnesota, North Dakota, South Carolina, Missouri, California, Florida, Oklahoma and Ontario, Canada and sell products primarily in the United States.

Health Services consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging services and rental of diagnostic medical imaging equipment to various medical institutions located throughout the United States.

Food Ingredient Processing consists of IPH, which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries.

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, wastewater and HVAC systems construction, transportation and energy services. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and 6 Canadian provinces.

Corporate includes items such as corporate staff and overhead costs, the results of the company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

No single external customer accounts for 10% or more of the Company's revenues. Substantially all of the Company's long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Ft. Erie, Ontario, Canada.

Percent of Sales Revenue by Country for the Year Ended December 31:

	2007	2006	2005
United States of America	96.9%	97.2%	97.8%
Canada	1.3%	1.3%	1.1%
All Other Countries	1.8%	1.5%	1.1%

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for 2007, 2006 and 2005 is presented in the following table.

(in thousands)	2007	2006	2005
Operating Revenue			
Electric	$ 323,478	$ 306,014	$ 312,985
Plastics	149,012	163,135	158,548
Manufacturing	381,599	311,811	244,311
Health Services	130,670	135,051	123,991
Food Ingredient Processing	70,440	45,084	38,501
Other Business Operations	185,730	145,603	105,821
Corporate Revenue and Intersegment Eliminations	(2,042)	(1,744)	(2,288)
Total	$1,238,887	$1,104,954	$ 981,869
Depreciation and Amortization			
Electric	$ 26,097	$ 25,756	$ 24,397
Plastics	3,083	2,815	2,511
Manufacturing	13,124	11,076	9,447
Health Services	3,937	3,660	4,038
Food Ingredient Processing	3,952	3,759	3,399
Other Business Operations	2,058	2,330	2,225
Corporate	579	587	441
Total	$ 52,830	$ 49,983	$ 46,458
Interest Charges			
Electric	$ 9,405	$ 10,315	$ 10,271
Plastics	970	814	1,080
Manufacturing	8,546	6,550	4,516
Health Services	883	910	822
Food Ingredient Processing	177	481	165
Other Business Operations	1,234	988	686
Corporate and Intersegment Eliminations	(358)	(557)	919
Total	$ 20,857	$ 19,501	$ 18,459
Income Before Income Taxes			
Electric	$ 37,422	$ 38,802	$ 55,984
Plastics	13,452	22,959	22,803
Manufacturing	24,503	21,148	12,242
Health Services	2,626	3,909	6,875
Food Ingredient Processing	5,912	(6,325)	1,482
Other Business Operations	6,762	8,666	(827)
Corporate	(8,748)	(11,303)	(16,650)
Total	$ 81,929	$ 77,856	$ 81,909
Earnings Available for Common Shares			
Electric	$ 23,762	$ 23,445	$ 36,566
Plastics	8,314	14,326	13,936
Manufacturing	15,632	13,171	7,589
Health Services	1,427	2,230	4,007
Food Ingredient Processing	4,386	(4,115)	329
Other Business Operations	4,049	5,257	(488)
Corporate	(4,345)	(4,300)	(8,772)
Total	$ 53,225	$ 50,014	$ 53,167
Capital Expenditures			
Electric	$ 104,288	$ 35,207	$ 30,479
Plastics	3,305	5,504	3,636
Manufacturing	42,786	20,048	16,112
Health Services	5,276	4,720	3,095
Food Ingredient Processing	47	1,762	2,952
Other Business Operations	5,589	1,779	3,086
Corporate	694	428	609
Total	$ 161,985	$ 69,448	$ 59,969
Identifiable Assets			
Electric	$ 813,565	$ 689,653	$ 654,175

Plastics	77,971	80,666	76,573
Manufacturing	274,780	219,336	177,969
Health Services	64,824	66,126	67,066
Food Ingredient Processing	91,966	94,462	96,023
Other Business Operations	72,258	67,110	55,341
Corporate	59,390	41,008	40,648
Discontinued Operations	—	289	13,701
Total	$1,454,754	$1,258,650	$1,181,496

3. Rate and Regulatory Matters

Minnesota

General Rate Case—The electric utility filed a general rate case in Minnesota on October 1, 2007 requesting an interim rate increase of 5.4% effective November 30, 2007 and a final total rate increase of approximately 11%. However, the electric utility is proposing to share asset-based wholesale margins through the FCA, so the final overall customer impact would be an increase of approximately 6.7%. The electric utility's interim rate request was approved and will remain in effect for all Minnesota customers until the Minnesota Public Utilities Commission (MPUC) makes a final determination on the final request, which is expected by August 1, 2008. If the MPUC approves final rates that are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need—On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt transmission lines. These lines would help ensure continued reliable electricity service in Minnesota and the surrounding region by upgrading and expanding the high-voltage transmission network and providing capacity for more wind energy resources to be developed in southern and western Minnesota, eastern North Dakota and South Dakota. The proposed lines would span more than 600 miles and represent one of the largest single transmission initiatives in the region in several years. The MPUC is expected to decide if the lines are needed by early 2009. The MPUC would determine routes for the new lines in separate proceedings. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are complete (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading the project, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. The electric utility's 2008 — 2012 capital budgets include $67 million for CapX 2020 expenditures.

Renewable Energy Standards, Conservation and Renewable Resource Riders—In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric utility to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards.

Under the Next Generation Energy Act passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover charges incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to recover the costs of qualifying renewable energy projects to supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can now be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval in an integrated resource plan or certificate of need proceeding before the MPUC. Renewable resource costs eligible for recovery may include return or investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses. The electric utility has requested approval of a renewable resource rider that would allow recovery of eligible and prudently incurred costs for its qualifying renewable energy project investments. The proposed rider would cover the Minnesota jurisdictional portion of such eligible costs. The electric utility expects to receive MPUC approval of its proposed rider in 2008.

In addition, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a tariff to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a certificate of need proceeding or certified by the MPUC as a Minnesota priority transmission project. Such transmission cost recovery riders would allow a return on investments at the level approved in the utility's last general rate case. The electric utility is also preparing to file a proposed rider to recover its share of costs of transmission infrastructure upgrades projects. The electric utility currently expects to file its transmission cost recovery tariff and receive MPUC approval during 2008.

Recovery of MISO Costs—In December 2005, the MPUC issued an order denying the electric utility's request to allow recovery of certain MISO-related costs through the FCA in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. The electric utility recorded a $1.9 million reduction in revenue and a refund payable in December 2005 to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The MPUC's final order was issued on February 24, 2006 requiring jurisdictional investor-owned utilities in the state to participate with the Minnesota Department of Commerce (MNDOC) and other parties in a proceeding that would evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The February 24, 2006 order eliminated the refund provision from the December 2005 order and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the utility's next general rate case. As a result, the electric utility recognized $1.9 million in revenue and reversed the refund payable in February 2006. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006.

In an order issued on December 20, 2006 the MPUC stated that except for schedule 16 and 17 administrative costs, discussed below, each petitioning utility may recover the charges imposed by the MISO for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of the utility's FCA from the period April 1, 2005 through a period of at least three years after the date of the order. The MPUC also ordered the utilities to refund schedule 16 and 17 costs collected through the FCA since the inception of MISO Day 2 Markets in April 2005 and stated that each petitioning utility may use deferred accounting for MISO schedule 16 and 17 costs incurred since April 1, 2005. That deferred accounting may continue for ongoing schedule 16 and 17 costs, without the accumulation of interest, until the earlier of March 1, 2009 or the utility's next electric rate case. According to the order, a utility may, in its next rate case, seek to recover schedule 16 and 17 costs at an appropriate level of base rate recovery, provided it shows those costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. Also, a utility may seek to recover schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a general rate case, subject to final MPUC approval. Pursuant to this December 20, 2006 order, the electric utility was ordered to refund $446,000 in MISO schedule 16 and 17 costs to Minnesota retail customers through the FCA over a twelve-month period beginning in January 2007. As of December 31, 2007 the electric utility had refunded $407,000 of the $446,000 and deferred $855,000 in MISO schedule 16 and 17 costs. The electric utility has also requested recovery of the deferred costs and recovery of the ongoing costs in its pending general rate case. The Residential and Small Business Utilities Division of the Office of the Attorney General (RUD-OAG) has appealed the December 20, 2006 order to the Minnesota Court of Appeals.

Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report)—The MNDOC and the electric utility identified two operational situations which are not covered in the approved method for allocating MISO costs contained in the final December 20, 2006 MPUC order discussed above. One relates to plants not expected to be available for retail but that produce energy in certain hours, resulting in wholesale sales. The other situation is the sale of Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007 the electric utility determined its Minnesota customers' portion of costs associated with these situations to be $765,000. The data was provided to the MNDOC during the course of the MNDOC's review of the AAA Report. The electric utility offered to refund $765,000 to its Minnesota customers to settle this and other issues raised by the MNDOC in the AAA Report docket before the MPUC and the MNDOC accepted the offer in October 2007 and recommended that the MPUC include the refund in its final order. The electric utility also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. The electric utility agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted the electric utility's refund offer and modifications and closed this docket on February 6, 2008. In December 2007, the electric utility recorded a liability and a reduction to revenue of $805,000 for the amount of the refund offer and similar revenues collected subsequent to June 30, 2007.

Claims of Improper Regulatory Filings—In September 2004, the Company provided a letter to the MPUC summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. On November 30, 2004 the electric utility filed a report with the MPUC responding to these claims. In 2005, the Energy Division of the MNDOC, the RUD-OAG and the claimants filed comments in response to the report, to which the electric utility filed reply comments. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the electric utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The electric utility filed these documents with the MPUC in the second quarter of 2006. The electric utility received comments on its filings from the MNDOC and the claimants and filed reply comments in August 2006.

The MNDOC recommended accepting the revised Regulatory Compliance Plan and the chart of accounts definition. The electric utility filed supplemental comments related to its Corporate Allocation Manual in November 2006. The electric utility also agreed to file a general rate case in Minnesota on or before October 1, 2007. At a MPUC hearing on January 25, 2007 all remaining open issues were resolved. The MPUC accepted the electric utility's compliance filing with minor changes, agreed to allow the electric utility to calculate corporate cost allocations as proposed, determined not to conduct any further review at this time and required the electric utility to include all of the Company's short-term debt in its calculations of allowance for funds used during construction. The electric utility agreed to provide the MPUC the results of the current FERC operational audit when available, compare the corporate allocation method to a commonly accepted methodology in the next rate case, and provide the results of the Company's investigation relating to a 2007 hotline complaint. The Company recorded a noncash charge to Other Income and Deductions of $3.3 million in 2006 related to the disallowance of a portion of capitalized costs of funds used during construction from the electric utility's rate base. On December 12, 2007 the MPUC issued its order closing the investigation subject to the Company's continuing responsibility to file the report on its FERC operational audit as soon as it becomes available and subject to any further development of the record required in the electric utility's pending general rate case.

North Dakota

In February 2005, the electric utility filed a petition with the North Dakota Public Service Commission (NDPSC) to seek recovery of certain MISO-related costs through the FCA. The NDPSC granted interim recovery through the FCA in April 2005, but similar to the decision of the MPUC, conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007, the NDPSC approved a settlement agreement between the electric utility and an intervener representing several large industrial customers in North Dakota. When the MISO Day 2 energy market began in April 2005, the characterization of some of the electric utility's energy costs changed, though the essential nature of those costs did not. Fuel and purchased energy costs incurred to serve retail customers are recoverable through the FCA in North Dakota. Under the approved settlement agreement, the electric utility will refund to North Dakota customers the schedule 16 and 17 costs collected through the FCA since April 2005. The electric utility can defer recognition of these costs and request recovery of them in its next general rate case. Purchase Power — Electric System Use expense was reduced and an offsetting regulatory asset was established for the amount of the refund. The refund amount of $493,000 was credited to North Dakota customers through the FCA beginning in October 2007. Also as part of the settlement, the electric utility agreed to file a general rate case in North Dakota between November 1 and December 31, 2008. As of December 31, 2007 the electric utility had deferred $576,000 in MISO schedule 16 and 17 costs in North Dakota pending the allowed recovery of those costs in its next rate case.

Federal

Revenue Sufficiency Guarantee (RSG) Charges—On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time RSG charges that were not allocated to day-ahead virtual supply offers in accordance with MISO's Transmission and Energy Markets Tariff (TEMT) going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006 the FERC issued a Notice of Extension of Time, permitting MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund to customers the amounts due, with interest, from April 1, 2005 and the requirement to submit a compliance filing. The Notice stated that the order on rehearing would provide the appropriate guidance regarding the timing of compliance filing. On October 26, 2006 the FERC issued an order on rehearing of the April 25, 2006 order, stating it would not require refunds related to real-time RSG charges that had not been allocated to day-ahead virtual supply offers in accordance with MISO's TEMT going back to the commencement of the MISO Day 2 market in April 2005. However, the FERC ordered prospective allocation of RSG charges to virtual transactions consistent with the TEMT to prevent future inequity and directed MISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs that virtual supply offers cause within 60 days of the October 26, 2006 order. On December 27, 2006 the FERC issued an order granting rehearing of the October 26, 2006 order.

On March 15, 2007 the FERC issued an order denying requests for rehearing of the RSG rehearing order dated October 27, 2006. In the March 15, 2007 order on rehearing, the FERC stated that its findings in the April 25, 2006 RSG order that virtual offers should share in the allocation of RSG costs, per the terms of the currently effective tariff, served as notice to market participants that virtual offers, for those market participants withdrawing energy, were liable for RSG charges. FERC clarified that the RSG rehearing order's waiver of refunds applies to the period before that order, from market start-up in April 2005 until April 24, 2006. After that date, virtual supply offers are liable for RSG costs and therefore, to the extent virtual supply offers were not assessed RSG costs, refunds are due for the period starting April 25, 2006.

On November 5, 2007 the FERC issued two orders related to the RSG proceeding. In the first order, the FERC accepted the MISO's April 17, 2007 RSG compliance filing to comply with the FERC's March 15, 2007 RSG order. The compliance reinserted language requiring the actual withdrawal of energy by market participants, restored the MISO's original TEMT language allocating RSG costs to virtual transactions, revised the effective date for allocation to imports, provided an explanation of its efforts to reflect partial-hour revenue determinations in its software development, and revised several definitions. The second related RSG order issued by FERC on November 5, 2007 was its order on rehearing on its April 25, 2006 order in which it rejected the MISO's proposal to remove references to virtual supply from the TEMT provisions related to calculating RSG charges (FERC Docket Nos. ER04-691-084 and ER04-691-086). In this order, the FERC denied the requests for rehearing of the RSG second rehearing order (the electric utility was one of the parties that sought rehearing) and FERC denied all requests for rehearing of the RSG compliance order.

In the RSG compliance order, the FERC rejected the MISO's proposal to allocate costs based on net virtual offers, i.e., virtual offers minus virtual bids, and clarified that the currently effective tariff, which allocates RSG costs to virtual supply offers, remains in effect. In the RSG second rehearing order, the FERC clarified that for those market participants withdrawing energy, to the extent virtual supply offers were not assessed RSG costs, refunds were due for the period starting April 25, 2006.

The electric utility recorded a $1.7 million ($1.0 million net-of-tax) charge to earnings in the first quarter of 2007 based on an internal estimate of the net impact of MISO reallocating RSG charges in response to the FERC order on rehearing. In May 2007, MISO informed affected market participants of the impact of reallocating charges based on its interpretation of the FERC order on rehearing. Based on MISO's interpretation of the order on rehearing, the electric utility estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the electric utility. Accordingly, the electric utility revised its first quarter estimated charge of $1.7 million ($1.0 million net-of-tax) to zero in the second quarter of 2007. The electric utility is awaiting FERC's response to MISO's December 5, 2007 RSG compliance filing and cannot determine what financial impact, if any, the filing will have on the Company's consolidated results of operations. However, MISO has stated there will be no additional resettlements related to this matter.

Transmission Practices Audit—The Division of Operation Audits of the FERC Office of Market Oversight and Investigations (OMOI) commenced an audit of the electric utility's transmission practices in 2005. The purpose of the audit is to determine whether and how the electric utility's transmission practices are in compliance with the FERC's applicable rules and regulations and tariff requirements and whether and how the implementation of the electric utility's waivers from the requirements of Order No. 889 and Order No. 2004 restricts access to transmission information that would benefit the electric utility's off-system sales. The Division of Operation Audits of the OMOI has not issued an audit report. The Company cannot predict if the results of the audit will have any impact on the Company's consolidated financial statements.

Big Stone II Project

On June 30, 2005 the electric utility and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant's nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules have been established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

The electric utility and the coalition of six other electric providers filed an application for a Certificate of Need for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. Evidentiary hearings were conducted in December 2006 and all parties submitted legal briefs. The Administrative Law Judges (ALJs) on August 15, 2007 recommended approval of the Certificate of Need subject to potential conditions. The electric utility and project participants addressed the ALJs' recommended potential conditions in an August 31, 2007 proposed settlement agreement with the MNDOC that was entered into the record of the Certificate of Need/Route Permit dockets. The MPUC had not acted on the applications or the proposed settlement agreement when Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. On October 19, 2007 the MPUC requested that the ALJs recommence proceedings in the matter and that the remaining project participants file testimony describing and supporting a revised Big Stone II project. The remaining five participants filed testimony on November 13, 2007. On December 3, 2007 the ALJs issued an order refining the scope of the additional proceedings. Evidentiary hearings were held on January 23-25, 2008. The electric utility anticipates the ALJs will issue their report and recommendation in March 2008 and the MPUC will decide the matters in April 2008. The electric utility's integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. In addition to approval of the Certificate of Need/Route Permit applications for the transmission line project, approval of this IRP is pending with the MPUC.

A filing in North Dakota for an advanced determination of prudence of Big Stone II was made by the electric utility in November 2006. Evidentiary hearings were held in June 2007. The NDPSC decision was delayed because of the change in ownership of the project. The administrative law judge in the matter scheduled supplemental hearings in April 2008.

The electric utility and the coalition of six other electric providers filed an Energy Conversion Facility Siting Permit Application for Big Stone II with the South Dakota Public Utilities Commission (SDPUC) on July 21, 2005. The permit was granted by the SDPUC on July 14, 2006 but was appealed by a group of interveners on the basis that carbon dioxide concerns had not been adequately addressed. In February 2007, a South Dakota circuit court judge issued an opinion affirming the decision of the SDPUC to grant the siting permit for Big Stone II. The permit was appealed to the South Dakota Supreme Court. On January 16, 2008 the South Dakota Supreme Court unanimously affirmed the SDPUC's decision to grant Big Stone II project participants a site permit. A permit application for the South Dakota portion of the transmission line for Big Stone II was filed with the SDPUC on January 16, 2006 and was approved by the SDPUC on January 2, 2007.

As of December 31, 2007 the electric utility has capitalized $8.2 million in costs related to the planned construction of Big Stone II. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

4. Regulatory Assets and Liabilities

The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

(in thousands)	December 31, 2007	December 31, 2006
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$ 26,933	$ 36,736
Accrued Cost-of-Energy Revenue	19,452	10,735
Deferred Income Taxes	8,733	11,712
Reacquisition Premiums	3,745	2,694
MISO Schedule 16 and 17 Deferred Administrative Costs — MN	855	541
Deferred Marked-to-Market Losses	771	—
MISO Schedule 16 and 17 Deferred Administrative Costs — ND	576	—
Deferred Conservation Program Costs	518	1,036
Accumulated ARO Accretion/Depreciation Adjustment	345	249
Plant Acquisition Costs	107	151
Total Regulatory Assets	$ 62,035	$ 63,854
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 57,787	$ 58,496
Deferred Income Taxes	4,502	5,228
Deferred Marked-to-Market Gains	271	—
Gain on Sale of Division Office Building	145	151
Total Regulatory Liabilities	$ 62,705	$ 63,875
Net Regulatory Liability Position	$ 670	$ 21

The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs were required to be recognized as components of Accumulated Other Comprehensive Loss in equity under SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans,* adopted in December 2006, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates. Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next nine months. The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*. Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 24.7 years. MISO Schedule 16 and 17 Deferred Administrative Costs — MN were excluded from recovery through the FCA in Minnesota in a December 2006 order issued by the MPUC. The MPUC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility's Minnesota general rate case filed on October 1, 2007. All deferred marked-to-market losses and gains are related to forward purchases of energy scheduled for delivery in January and February of 2008. MISO Schedule 16 and 17 Deferred Administrative Costs — ND were excluded from recovery through the FCA in North Dakota in an August 2007 order issued by the NDPSC. The NDPSC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility's next general rate case in North Dakota scheduled to be filed in November or December of 2008. Deferred Conservation Program Costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. Plant Acquisition Costs will be amortized over the next 2.4 years. The Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred. The remaining regulatory assets and liabilities are being recovered from, or will be paid to, electric customers over the next 30 years.

If for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an extraordinary expense or income item in the period in which the application of SFAS No. 71 ceases.

5. Forward Energy Contracts Classified as Derivatives

Electricity Contracts

All of the electric utility's wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. The electric utility's objective in entering into forward contracts for the purchase and sale of energy is to optimize the use of its generating and transmission facilities and leverage its knowledge of wholesale energy markets in the region to maximize financial returns for the benefit of both its customers and shareholders. The electric utility's intent in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. The electric utility also enters into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales.

Electric revenues include $25,640,000 in 2007, $25,965,000 in 2006 and $46,397,000 in 2005 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts and sales of financial transmission rights and daily settlements of virtual transactions in the MISO market, broken down as follows for the years ended December 31:

(in thousands)	2007	2006	2005
Wholesale Sales — Company—Owned Generation	$ 20,345	$ 23,130	$ 24,799
Revenue from Settled Contracts at Market Prices	389,643	385,978	474,882
Market Cost of Settled Contracts	(387,682)	(383,594)	(457,728)
Net Margins on Settled Contracts at Market	1,961	2,384	17,154
Marked-to-Market Gains on Settled Contracts	31,243	20,950	11,118
Marked-to-Market Losses on Settled Contracts	(28,541)	(20,702)	(9,590)
Net Marked-to-Market Gain on Settled Contracts	2,702	248	1,528
Unrealized Marked-to-Market Gains on Open Contracts	5,117	2,215	5,678
Unrealized Marked-to-Market Losses on Open Contracts	(4,485)	(2,012)	(2,762)
Net Unrealized Marked-to-Market Gain on Open Contracts	632	203	2,916
Wholesale Electric Revenue	$ 25,640	$ 25,965	$ 46,397

The following tables show the effect of marking to market forward contracts for the purchase and sale of energy on the Company's consolidated balance sheets:

(in thousands)	December 31, 2007	December 31, 2006
Current Asset — Marked-to-Market Gain	$ 5,210	$ 2,215
Regulatory Asset — Deferred Marked-to-Market Loss	771	—
Total Assets	5,981	2,215
Current Liability — Marked-to-Market Loss	(5,078)	(2,012)
Regulatory Liability — Deferred Marked-to-Market Gain	(271)	—
Total Liabilities	(5,349)	(2,012)
Net Fair Value of Marked-to-Market Energy Contracts	$ 632	$ 203

(in thousands)	Year ended December 31, 2007
Fair Value at Beginning of Year	$ 203
Amount Realized on Contracts Entered into in 2006 and Settled in 2007	(203)
Changes in Fair Value of Contracts Entered into in 2006	—
Net Fair Value of Contracts Entered into in 2006 at Year End 2007	—
Changes in Fair Value of Contracts Entered into in 2007	632
Net Fair Value at End of Year	$ 632

The $632,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market as of December 31, 2007 is expected to be realized on physical settlement or settled by an offsetting agreement with the counterparty to the original contract as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2008	4th Quarter 2008	Total
Net Gain	$118	$514	$632

Of the forward energy sales contracts that are marked to market as of December 31, 2007, 97.6% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $56,000 in unrealized gains recognized on the open sales contracts.

Natural Gas Contracts

In the third quarter of 2006, IPH entered into forward natural gas swaps on the New York Mercantile Exchange (NYMEX) market to hedge its exposure to fluctuations in natural gas prices related to approximately 50% of its anticipated natural gas needs through March 2007 for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts were derivatives subject to mark-to-market accounting but they did not qualify for hedge accounting treatment as cash flow hedges because the changes in the NYMEX prices did not correspond closely enough to changes in natural gas prices at the locations of physical delivery. Therefore, IPH included net changes in the market values of these forward contracts in net income as components of cost of goods sold in the period of recognition.

Cost of goods sold in the food ingredient processing segment includes $542,000 in losses in 2006, of which $171,000 was realized, related to IPH's forward natural gas contracts on NYMEX as a result of declining natural gas prices in 2006. The net fair value of contracts held as of December 31, 2006 was ($371,000). Of the $371,000 in unrealized marked-to-market losses on forward natural gas contracts IPH had outstanding on December 31, 2006, $62,000 was reversed and $309,000 was realized on settlement in the first quarter of 2007.

6. Common Shares and Earnings Per Share

Following is a reconciliation of the Company's common shares outstanding from December 31, 2006 through December 31, 2007:

Common Shares Outstanding, December 31, 2006	29,521,770
Issuances:	
Stock Options Exercised	298,601
Directors' Compensation:	
Restricted Shares	15,200
Unrestricted Shares	885
Vesting of Restricted Stock Units	4,522
Restricted Shares Issued for Employee Compensation	17,300
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(8,409)
Restricted Shares Forfeited	(80)
Common Shares Outstanding, December 31, 2007	29,849,789

Stock Incentive Plan

The 1999 Stock Incentive Plan, as amended (Incentive Plan), provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 3,600,000 common shares are authorized for granting stock awards under the Incentive Plan, which terminates on December 13, 2013.

Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. The number of common shares authorized to be issued under the Purchase Plan is 900,000, of which 397,156 were still available for purchase as of December 31, 2007. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for the Purchase Plan, 52,558 common shares were purchased in the open market in 2007, 53,258 common shares were purchased in the open market in 2006 and 69,401 common shares were purchased in the open market in 2005 The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive for the purpose of calculating diluted earnings per share during the investment period.

Dividend Reinvestment and Share Purchase Plan
On August 30, 1996 the Company filed a shelf registration statement with the Securities and Exchange Commission (SEC) for the issuance of up to 2,000,000 common shares pursuant to the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by shareholders or customers who participate in the Plan to be either new issue common shares or common shares purchased in the open market. From June 1999 through December 2003, common shares needed for the Plan were purchased in the open market. From January through October 2004 new shares were issued for this Plan. Starting in November 2004 the Company began purchasing common shares in the open market. Through December 31, 2007, 944,507 common shares had been issued to meet the requirements of the Plan.

Shareholder Rights Plan
On January 27, 1997 the Company's Board of Directors declared a dividend of one preferred share purchase right (Right) for each outstanding common share held of record as of February 15, 1997. One Right was also issued with respect to each common share issued after February 15, 1997. The Rights expired pursuant to their terms on January 27, 2007.

Earnings Per Share
Basic earnings per common share are calculated by dividing earnings available for common shares by the weighted average number of common shares outstanding during the period. Diluted earnings per common share are calculated by adjusting outstanding shares, assuming conversion of all potentially dilutive stock options. Stock options with exercise prices greater than the market price are excluded from the calculation of diluted earnings per common share. Nonvested restricted shares granted to the Company's directors and employees are considered dilutive for the purpose of calculating diluted earnings per share but are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. Underlying shares related to nonvested restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share. Shares expected to be awarded for stock performance awards granted to executive officers are considered dilutive for the purpose of calculating diluted earnings per share.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the years ended December 31, 2007, 2006 and 2005:

Year	Options Outstanding	Range of Exercise Prices
2007	—	NA
2006	210,250	$29.74 - $31.34
2005	237,624	$28.66 - $31.34

7. Share-Based Payments

On January 1, 2006 the Company adopted the accounting provisions of SFAS No. 123(R) (revised 2004), *Share-Based Payment,* on a modified prospective basis. SFAS No. 123(R) is a revision of SFAS No. 123, *Accounting for Stock-based Compensation,* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees.* Under SFAS No. 123(R), the Company records stock-based compensation as an expense on its income statement over the period earned based on the estimated fair value of the stock or options awarded on their grant date. The Company elected the modified prospective method of adopting SFAS No. 123(R), under which prior periods are not retroactively revised. The valuation provisions of SFAS No. 123(R) apply to awards granted after the effective date. Estimated stock-based compensation expense for awards granted prior to the effective date but that remain nonvested on the effective date will be recognized over the remaining service period using the compensation cost estimated for the SFAS No. 123 pro forma disclosures. Additionally, the adoption of SFAS No. 123(R) resulted in the reclassification of $798,000 in credits related to outstanding restricted share-based compensation from equity on the Company's consolidated balance sheet to a liability on January 1, 2006 because of income tax withholding provisions in the share-based award agreements. The adoption of SFAS 123(R) also resulted in the elimination of Unearned Compensation from the equity section of the Company's consolidated balance sheet on January 1, 2006 by netting the account balance of $1,720,000 against Premium on Common Shares.

As of December 31, 2007 the total remaining unrecognized amount of compensation expense related to stock-based compensation was approximately $4.6 million (before income taxes), which will be amortized over a weighted-average period of 2.3 years.

The Company has six share-based payment programs. The effect of SFAS No. 123(R) accounting on each of these programs is explained in the following paragraphs.

Purchase Plan

The Purchase Plan allows employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six month investment period. Under SFAS 123(R), the Company is required to record compensation expense related to the 15% discount which was not required under APB No. 25. The 15% discount resulted in compensation expense of $257,000 in 2007 and $235,000 in 2006. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company.

Stock Options Granted Under the Incentive Plan

Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company's common stock. All of the options granted had vested or were forfeited as of December 31, 2007. The exercise price of the options granted was the average market price of the Company's common stock on the grant date. These options were not compensatory under APB No. 25 accounting rules. Under SFAS No. 123(R) accounting, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under SFAS No. 123(R) accounting, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan has been based on the Black-Scholes option pricing model.

Under the modified prospective application of SFAS No. 123(R) accounting requirements, the difference between the intrinsic value of nonvested options and the fair value of those options of $362,000 on January 1, 2006 was recognized on a straight-line basis as compensation expense over the remaining 16 months of the options vesting period. Accordingly, the Company recorded compensation expense of $91,000 in 2007 and $271,000 in 2006 related to options that were not vested as of January 1, 2006.

Had compensation costs for the stock options issued been determined based on estimated fair value at the award dates, as prescribed by SFAS No. 123, the Company's net income for 2005 would have decreased as presented in the table below:

(in thousands, except per share amounts)	2005
Net Income	
As Reported	$ 62,551
Total Stock-Based Employee Compensation Expense Determined Under Fair Value-Based Method for All Awards Net of Related Tax Effects	(640)
Pro Forma	$ 61,911
Basic Earnings Per Share As Reported	$ 2.12
Pro Forma	$ 2.09
Diluted Earnings Per Share As Reported	$ 2.11
Pro Forma	$ 2.08

Presented below is a summary of the stock options activity:

	2007		2006		2005	
Stock Option Activity	Options	Average Exercise Price	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	1,091,238	$ 25.74	1,237,164	$ 25.58	1,508,277	$ 25.35
Granted	—	—	—	—	74,900	24.93
Exercised	298,601	25.73	107,458	22.88	257,948	22.90
Forfeited	5,500	28.85	38,468	28.60	88,065	28.79
Outstanding, End of Year	787,137	25.73	1,091,238	25.74	1,237,164	25.58
Exercisable, End of Year	787,137	25.73	1,049,713	25.69	1,095,272	25.16
Cash Received for Options Exercised	$ 7,682,000		$ 2,458,000		$5,911,000	
Fair Value of Options Granted During Year	none granted		none granted		$ 4.76	

The fair values of the options granted in 2005 were estimated using the Black-Scholes option-pricing model under the following assumptions:

	2005
Risk-Free Interest Rate	4.3%
Expected Lives	7 years
Expected Volatility	25.4%
Dividend Yield	4.4%

The following table summarizes information about options outstanding as of December 31, 2007:

Options Outstanding and Exercisable			
Range of Exercise Prices	Outstanding and Exercisable as of 12/31/07	Weighted-Average Remaining Contractual Life (yrs)	Weighted-Average Exercise price
$18.80-$21.94	175,210	2.0	$ 19.62
$21.95-$25.07	40,100	7.3	$ 24.93
$25.08-$28.21	429,927	4.0	$ 26.50
$28.22-$31.34	141,900	4.2	$ 31.17

Restricted Stock Granted to Directors

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's Board of Directors as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the four-year vesting period of the restricted shares based on the market value of the Company's common stock on the grant date. Under the modified prospective application of SFAS No. 123(R) accounting requirements, compensation expense related to nonvested restricted shares outstanding will be recorded based on the estimated fair value of the restricted shares on their grant dates. On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 15,200 shares of restricted stock to the Company's nonemployee directors under the Incentive Plan.

Presented below is a summary of the status of directors' restricted stock awards for the years ended December 31:

Directors' Restricted Stock Awards	2007		2006		2005	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	32,775	$ 27.27	27,000	$ 26.32	22,600	$ 27.61
Granted	15,200	$ 35.04	19,800	$ 28.24	11,700	$ 24.93
Vested	13,875	$ 27.10	14,025	$ 26.82	7,300	$ 28.09
Forfeited	—		—		—	
Nonvested, End of Year	34,100	$ 30.80	32,775	$ 27.27	27,000	$ 26.32
Compensation Expense Recognized		$ 454,000		$ 401,000		$261,000
Fair Value of Shares Vested in Year		$ 376,000		$ 376,000		$205,000

Restricted Stock Granted to Employees

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the vesting periods of the restricted shares based on the market value of the Company's common stock on the grant date. Because of income tax withholding provisions in the restricted stock award agreements related to restricted stock granted to employees prior to 2006, the value of these grants is considered variable, which, under SFAS No. 123(R), will require the offsetting credit to compensation expense to be recorded as a liability. Under the modified prospective application of SFAS No. 123(R) accounting requirements and accounting rules for variable awards, compensation expense related to nonvested restricted shares granted to employees will be recorded based on the estimated fair value of the restricted shares on their grant dates and adjusted for the estimated fair value of any nonvested restricted shares on each subsequent reporting date. The reporting date fair value of nonvested restricted shares granted prior to 2006 under this program is based on the average market value of the Company's common stock on the reporting date—$34.575 on December 31, 2007.

In 2006, under SFAS No. 123(R), the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the estimated fair value of the restricted stock grants. In 2005, under APB No. 25, the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the intrinsic value of the restricted stock grants. The equity account, Unearned Compensation, was credited when compensation expense was recorded related to these shares under APB No. 25 accounting. Under SFAS 123(R) accounting, a current liability account is credited when compensation expense is recorded. Accumulated liabilities related to nonvested restricted shares issued to employees under this program prior to 2006 will be reversed and credited to the Premium on Common Shares equity account as the shares vest.

In 2006, the income tax withholding provisions in the Company's restricted stock award agreements were revised to only allow withholding at statutory withholding rates. The fair value of restricted shares issued under the revised restricted stock award agreements is not considered a liability under SFAS No. 123(R), so compensation expense related to awards granted after 2005 will be based on their grant-date fair value and recognized over the vesting period of the awards with the offsetting credit charged directly to equity. On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 600 shares of restricted stock to a newly hired employee under the Incentive Plan. The restricted shares vest 50% on issuance and 50% on April 8, 2008 and are eligible for full dividend and voting rights. The grant-date fair value of the restricted shares was $35.30 per share, the average market price of the shares on their grant date. On October 29, 2007 the Compensation Committee of the Company's Board of Directors granted 16,700 shares of restricted stock to the Company's executive officers under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2008 through 2011 and are eligible for full dividend and voting rights. The grant-date fair value of the restricted shares was $35.84 per share, the average market price of the shares on their grant date.

Presented below is a summary of the status of employees' restricted stock awards for the years ended December 31:

Employees' Restricted Stock Awards	2007		2006		2005	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Nonvested, Beginning of Year	31,666	$ 31.47	72,974	$ 28.91	103,340	$ 25.31
Granted	17,300	$ 35.82	—		9,000	$ 26.31
Variable/Liability Awards Vested	24,608	$ 35.09	41,308	$ 28.98	39,126	$ 25.08
Nonvariable Awards Vested	300	$ 35.30	—		—	
Forfeited	—		—		240	$ 26.68
Nonvested, End of Year	24,058	$ 35.46	31,666	$ 31.47	72,974	$ 28.91
Compensation Expense Recognized		$ 549,000		$ 815,000		$1,118,000
Fair Value of Variable Awards Vested/Liability Paid		$ 863,000		$1,197,000		$ 981,000
Fair Value of Nonvariable Awards Vested		$ 11,000		—		—

<u>Restricted Stock Units Granted to Employees</u>

On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 23,450 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2011, the date the units vest. The Company uses a Monte Carlo valuation method to determine the grant-date fair value of restricted stock units. The grant-date fair value of each restricted stock unit granted on April 9, 2007 was $30.07 per share. The weighted average contractual term of stock units outstanding as of December 31, 2007 is 2.8 years.

Presented below is a summary of the status of employees' restricted stock unit awards for the years ended December 31:

	2007		2006	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	38,615	$ 24.65	—	$ —
Granted	23,450	$ 30.07	47,425	$ 25.41
Converted	4,850	$ 26.95	7,450	$ 29.55
Forfeited	1,735	$ 27.03	1,360	$ 24.36
Nonvested, End of Year	55,480	$ 26.66	38,615	$ 24.65
Compensation Expense Recognized		$ 383,000		$ 427,000
Fair Value of Units Converted in Year		$ 131,000		$ 220,000

Stock Performance Awards granted to Executive Officers

The Compensation Committee of the Company's Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under APB No. 25 accounting, these awards were valued based on the average market price of the underlying shares of the Company's common stock on the award grant date, multiplied by the estimated probable number of shares to be awarded at the end of the performance measurement period with compensation expenses recorded ratably over the related three-year measurement period. Compensation expense recognized was adjusted at each reporting date subsequent to the grant date of the awards for the difference between the market value of the underlying shares on their grant date and the market value of the underlying shares on the reporting date. Under the modified prospective application of SFAS No. 123(R) accounting requirements, the amount of compensation expense that will be recorded subsequent to January 1, 2006 related to awards granted in 2004 and 2005 and outstanding on December 31, 2006 is based on the estimated grant-date fair value of the awards as determined under the Black-Scholes option pricing model.

On October 29, 2007 the Compensation Committee of the Company's Board of Directors granted performance share awards to the Company's executive officers under the Incentive Plan. Under these awards, the Company's executive officers could earn up to an aggregate of 109,000 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance period of January 1, 2007 through December 31, 2009. The aggregate target share award is 54,500 shares. Actual payment may range from zero to 200 percent of the target amount. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. In accordance with SFAS No. 123(R), the Company will estimate the fair value of the common shares projected to be awarded on the date of grant under a Monte Carlo valuation method and record compensation expense over the remaining performance period.

The offsetting credit to amounts expensed related to the stock performance awards is included in common shareholders' equity. The table below provides a summary of amounts expensed for the stock performance awards:

Performance Period	Maximum Shares Subject To Award	Shares Used To Estimate Expense	Fair Value	Expense Recognized in the Year Ended December 31, 2007	2006	2005	Shares Awarded
2007-2009	109,000	67,263	$ 38.01	$ 852,000	$ —	$ —	
2006-2008	88,050	58,700	$ 25.95	508,000	508,000	—	
2005-2007	75,150	50,872	$ 22.10	375,000	375,000	490,000	62,625
2004-2006	70,500	23,500	$ 23.90	—	187,000	453,000	23,500
Total				$1,735,000	$1,070,000	$943,000	86,125

8. Retained Earnings Restriction

The Company's Articles of Incorporation, as amended, contain provisions that limit the amount of dividends that may be paid to common shareholders by the amount of any declared but unpaid dividends to holders of the Company's cumulative preferred shares. Under these provisions none of the Company's retained earnings were restricted at December 31, 2007.

9. Commitments and Contingencies

At December 31, 2007 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $35,835,000. For capacity and energy requirements, the electric utility has agreements extending through 2032 at annual costs of approximately $23,111,000 in 2008, $22,929,000 in 2009, $11,377,000 in 2010, $5,565,000 in 2011 and $5,565,000 in 2012, and $93,286,000 for the years beyond 2012.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2010 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $183,209,000 or to make payments in lieu thereof, under these contracts. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

IPH has commitments of approximately $7,200,000 for the purchase of a portion of its 2008 raw potato supply requirements.

The amounts of future operating lease payments are as follows:

(in thousands)	Electric	Nonelectric	Total
2008	$ 2,560	$ 40,722	$ 43,282
2009	2,560	37,504	40,064
2010	2,203	26,812	29,015
2011	1,446	14,008	15,454
2012	951	2,669	3,620
Later years	3,206	3,603	6,809
Total	$ 12,926	$ 125,318	$ 138,244

The electric future operating lease payments are primarily related to coal rail-car leases. The nonelectric future operating lease payments are primarily related to medical imaging equipment. Rent expense from continuing operations was $47,904,000, $44,254,000 and $37,798,000 for 2007, 2006 and 2005, respectively.

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2007 will not be material.

10. Short-Term and Long-Term Borrowings

Short-Term Debt

As of December 31, 2007 the Company had $95.0 million in short-term debt outstanding at a weighted average interest rate of 6.3%. As of December 31, 2006 the Company had $38.9 million in short-term debt outstanding at a weighted average interest rate of 5.7%. The average interest rate paid on short-term debt was 6.0% in 2007 and 5.8% in 2006.

The Company’s $150 million line of credit pursuant to a Credit Agreement dated as of April 26, 2006 with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West was scheduled to expire on April 26, 2009 but was terminated and replaced by a new $200 million credit agreement (the Varistar Credit Agreement) entered into by Varistar Corporation (Varistar), a wholly-owned subsidiary of the Company, on October 2, 2007. Varistar entered into the Varistar Credit Agreement with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. The Varistar Credit Agreement is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Varistar Credit Agreement expires on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on Varistar’s adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company’s credit ratings. Varistar’s obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Outstanding letters of credit issued by Varistar can reduce the amount available for borrowing under the line by up to $30 million. As of December 31, 2007, $95.0 million of the $200 million line of credit was in use and $14.9 million was restricted from use to cover outstanding letters of credit.

Otter Tail Corporation, dba Otter Tail Power Company and U.S. Bank National Association have a Credit Agreement (the Electric Utility Credit Agreement) providing for a separate $75 million line of credit. This line of credit is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its electric operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of the Company’s senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on September 1, 2008. As of December 31, 2007 no money was borrowed under the Electric Utility Credit Agreement.

Long-Term Debt
The Company has the ability to issue up to $256 million of common shares, cumulative preferred shares, debt and certain other securities from time to time under its universal shelf registration statement filed with the Securities and Exchange Commission on June 4, 2004 and declared effective on August 30, 2004. The Company issued no long-term debt under its universal shelf registration in 2007 or 2006.

At closings completed in August 2007 and October 2007, the Company issued $155 million aggregate principal amount of its senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The net proceeds from this initial closing were used to repay borrowings under the Company's $150 million line of credit that was terminated on October 2, 2007. The remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes, were issued and sold by the Company at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of the Company's 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of the Company's 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

In February 2007 the Company entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which the Company agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of the Company's senior notes due November 30, 2017 (the Cascade Note). On December 14, 2007 the Company issued the Cascade Note. The Cascade Note bears interest at a rate of 5.778% per annum. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of the Company's $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The proceeds of this financing were used to redeem the Company's $50 million 6.375% Senior Debentures due December 1, 2007. Cascade owned approximately 8.6% of the Company's outstanding common stock as of December 31, 2007.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, and the 2001 Note Purchase Agreement states the Company may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states the Company must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company.

The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement contain a number of restrictions on the businesses of the Company and its subsidiaries. In each case these include restrictions on the ability of the Company and certain of its subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

The Company's obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of its subsidiaries. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. The Company's Grant County and Mercer County Pollution Control Refunding Revenue Bonds require that the Company grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, a security interest in the assets of the electric utility if the rating on the Company's senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's).

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2007 for each of the next five years are $3,004,000 for 2008, $2,915,000 for 2009, $2,606,000 for 2010, $90,087,000 for 2011 and $10,463,000 for 2012.

Financial Covenants
The Electric Utility Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement and the Lombard US Equipment Finance note contain covenants by the Company not to permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, the Company's interest coverage ratio) to be less than 1.5 to 1. The note purchase agreements further restrict the Company from allowing its priority debt to exceed 20% of total capitalization. Financial covenants in the Varistar Credit Agreement require Varistar to maintain a fixed charge coverage ratio of not less than 1.25 to 1 and to not permit its cash flow leverage ratio to exceed 3.0 to 1. The Company and Varistar were in compliance with all of the covenants under their financing agreements as of December 31, 2007.

11. Class B Stock Options of Subsidiary

Class B Stock Options of Subsidiary
In connection with the acquisition of IPH in August 2004, IPH management and certain other employees elected to retain stock options for the purchase of 1,112 IPH Class B common shares valued at $1.8 million. The options are exercisable at any time and the option holder must deliver cash to exercise the option. Once the options are exercised for Class B shares, the Class B shareholder cannot put the shares back to the Company for 181 days. At that time, the Class B common shares are redeemable at any time during the employment of the individual holder, subject to certain limits on the total number of Class B common shares redeemable on an annual basis. The Class B common shares are nonvoting, except in the event of a merger, and do not participate in dividends but have liquidation rights at par with the Class A common shares owned by the Company. The value of the Class B common shares issued on exercise of the options represents an interest in IPH that changes as defined in the agreement. In 2005, options for 357 IPH Class B common shares were exercised and the Class B common shares were redeemed by IPH 181 days after issuance. In 2006, two of the retained stock options were forfeited.

In 2006, IPH granted 305 additional options to purchase IPH Class B Common Stock to five employees at an exercise price of $2,085.88 per option. The options vested immediately on issuance. On the date the options were granted, the value of a share of IPH Class B common stock was estimated to be $1,041.71. Therefore, the grant-date fair value of the options was $0 and no expense or liability was recorded related to these options under SFAS No. 123(R). In 2007, 125 options that were granted in 2006 were forfeited as a result of voluntary terminations. As of December 31, 2007 there were 933 options outstanding with a combined exercise price of $691,000, of which 753 options were "in-the-money" with a combined exercise price of $316,000.

12. Pension Plan and Other Postretirement Benefits

The following footnote reflects the adoption of SFAS No. 158, *Accounting for Defined Benefit Pension and Other Postretirement Plans*, in December 2006. The Company determined that the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Losses in equity as prescribed by SFAS No. 158.

Effective July 1, 2005 the Company remeasured its pension and other postretirement benefit plan obligations using the RP-2000 Combined Healthy Mortality table in place of the 1983 Group Annuity Mortality table (GAM '83) it used to measure its obligations and determine its annual costs under these plans in January 2005. The reason for the remeasurement was to update the mortality table to more accurately reflect current life expectancies of current employees and retirees included in the plans. Generally accepted accounting principles require that all assumptions used to measure plan obligations and determine annual plan costs be revised as of a remeasurement date. The following actuarial assumptions were updated as of the July 1, 2005 remeasurement date:

Key Assumptions and Data	January 1, 2005 through June 30, 2005	July 1, 2005 through December 31, 2005
Discount Rate	6.00%	5.25%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Social Security Wage Base	4.00%	3.50%
Rate of Inflation	3.00%	2.50%
Rate of Withdrawal	1% per year through age 54	2% per year through age 54
Mortality Table	GAM '83	RP-2000 projected to 2006
Market Value of Assets — Beginning of Period	$141,685,000	$142,547,832

Remeasuring t nowraphe Company's pension and other postretirement benefit plan obligations as of July 1, 2005 under the revised assumptions had the effect of increasing the Company's 2005 projected pension plan costs by $1,364,000, increasing its 2005 projected Executive Survivor and Supplemental Retirement Plan costs by $123,000 and increasing its 2005 projected costs for postretirement benefits other than pensions by $137,000.

Pension Plan

The Company's noncontributory funded pension plan covers substantially all electric utility and corporate employees hired prior to January 1, 2006. The plan provides 100% vesting after five vesting years of service and for retirement compensation at age 65, with reduced compensation in cases of retirement prior to age 62. The Company reserves the right to discontinue the plan but no change or discontinuance may affect the pensions theretofore vested. The Company's policy is to fund pension costs accrued. All past service costs have been provided for.

The pension plan has a trustee who is responsible for pension payments to retirees. Four investment managers are responsible for managing the plan's assets. An independent actuary assists the Company in performing the necessary actuarial valuations for the plan.

The plan assets consist of common stock and bonds of public companies, U.S. government securities, cash and cash equivalents. None of the plan assets are invested in common stock, preferred stock or debt securities of the Company.

Components of net periodic pension benefit cost:

(in thousands)	2007	2006	2005
Service Cost—Benefit Earned During the Period	$ 4,837	$ 5,057	$ 4,695
Interest Cost on Projected Benefit Obligation	10,790	10,435	9,721
Expected Return on Assets	(12,948)	(12,288)	(12,071)
Amortization of Prior-Service Cost	742	742	726
Amortization of Net Actuarial Loss	1,091	1,844	1,364
Net Periodic Pension Cost	$ 4,512	$ 5,790	$ 4,435

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2007	2006
Regulatory Assets:		
Unrecognized Prior Service Cost	$ (4,018)	$ (4,748)
Unrecognized Actuarial Loss	(17,115)	(21,771)
Total Regulatory Assets	(21,133)	(26,519)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	(120)	(132)
Unrecognized Actuarial Loss	(511)	(606)
Total Accumulated Other Comprehensive Loss	(631)	(738)
Prepaid Pension Cost	7,493	8,005
Net Amount Recognized — Noncurrent Liability	$ (14,271)	$ (19,252)

Funded status as of December 31:

(in thousands)	2007	2006
Accumulated Benefit Obligation	$(154,373)	$(153,816)
Projected Benefit Obligation	$(185,206)	$(186,760)
Fair Value of Plan Assets	170,935	167,508
Funded Status	$ (14,271)	$ (19,252)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations and prepaid pension cost over the two-year period ended December 31, 2007:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$167,508	$146,982
Actual Return on Plan Assets	8,013	24,856
Discretionary Company Contributions	4,000	4,000
Benefit Payments	(8,586)	(8,330)
Fair Value of Plan Assets at December 31	$170,935	$167,508
Estimated Asset Return	4.85%	17.24%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$186,760	$181,587
Service Cost	4,837	5,057
Interest Cost	10,790	10,435
Benefit Payments	(8,586)	(8,330)
Actuarial Gain	(8,595)	(1,989)
Projected Benefit Obligation at December 31	$185,206	$186,760
Reconciliation of Prepaid Pension Cost:		
Prepaid Pension Cost at January 1	$ 8,005	$ 9,795
Net Periodic Pension Cost	(4,512)	(5,790)
Discretionary Company Contributions	4,000	4,000
Prepaid Pension Cost at December 31	$ 7,493	$ 8,005

Weighted-average assumptions used to determine benefit obligations at December 31:

	2007	2006
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	3.75%	3.75%

Weighted-average assumptions used to determine net periodic pension cost for the year ended December 31:

	2007	2006
Discount Rate	6.00%	5.75%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%

To develop the expected long-term rate of return on assets assumption, the Company considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio.

Market-related value of plan assets—The Company's expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The Company bases actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gain or losses over a five-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

The assumed rate of return on pension fund assets for the determination of 2008 net periodic pension cost is 8.50%.

Measurement Dates:	2007	2006
Net Periodic Pension Cost	January 1, 2007	January 1, 2006
End of Year Benefit Obligations	January 1, 2007 projected to December 31, 2007	January 1, 2006 projected to December 31, 2006
Market Value of Assets	December 31, 2007	December 31, 2006

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 720
Amortization of Unrecognized Actuarial Loss	103
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	22
Amortization of Unrecognized Actuarial Loss	3
Total Estimated Amortization	$ 848

Cash flows—The Company is not required to make a contribution to the pension plan in 2008.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid out from plan assets:

(in thousands)	2008	2009	2010	2011	2012	Years 2013-2017
	$8,917	$9,073	$9,234	$9,641	$10,103	$59,365

The Company's pension plan asset allocations at December 31, 2007 and 2006, by asset category are as follows:

Asset Allocation	2007	2006
Large Capitalization Equity Securities	47.1%	49.3%
Small Capitalization Equity Securities	10.7%	11.6%
International Equity Securities	10.4%	10.6%
Total Equity Securities	68.2%	71.5%
Cash and Fixed-Income Securities	31.8%	28.5%
	100.0%	100.0%

The following objectives guide the investment strategy of the Company's pension plan (the Plan).

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of the Company.
- The Plan's assets should be invested with the objective of meeting current and future payment requirements while minimizing annual contributions and their volatility.
- The asset strategy reflects the desire to meet current and future benefit payments while considering a prudent level of risk and diversification.

The asset allocation strategy developed by the Company's Retirement Plans Administrative Committee is based on the current needs of the Plan, the investment objectives listed above, the investment preferences and risk tolerance of the committee and a desired degree of diversification.

The asset allocation strategy contains guideline percentages, at market value, of the total Plan invested in various asset classes. The strategic target allocation shown in the table that follows is a guide that will at times not be reflected in actual asset allocations that may be dictated by prevailing market conditions, independent actions of the Retirement Plans Administrative Committee and/or investment managers, and required cash flows to and from the Plan. The tactical range provides flexibility for the investment managers' portfolios to vary around the target allocation without the need for immediate rebalancing.

The Company's Retirement Plans Administrative Committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining the targeted allocation percentages listed in the table below.

Asset Allocation	Strategic Target	Tactical Range
Large capitalization equity securities	48%	40%-55%
Small capitalization equity securities	12%	9%-15%
International equity securities	10%	5%-15%
Total equity securities	70%	60%-80%
Fixed-income securities	30%	20%-40%

Executive Survivor and Supplemental Retirement Plan (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period. Life insurance carried on certain plan participants is payable to the Company on the employee's death. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

On January 31, 2005 the Board of Directors of the Company amended and restated the ESSRP to reduce future benefits effective January 1, 2005, which resulted in reduced expense to the Company. Effective January 1, 2005 new participants in the ESSRP accrue benefits under a new formula. The new formula is the same as the formula used under the Company's qualified defined benefit pension plan but includes bonuses in the computation of covered compensation and is not subject to statutory compensation and benefit limits. Individuals who became participants in the ESSRP before January 1, 2005 will receive the greater of the old formula or the new formula until December 31, 2010. On December 31, 2010, their benefit under the old formula will be frozen. After 2010, they will receive the greater of their frozen December 31, 2010 benefit or their benefit calculated under the new formula. The amendments to the ESSRP also provide for increased service credits for certain participants and eliminate certain distribution features.

On December 19, 2006 the Board of Directors of the Company approved an amendment to the ESSRP effective January 1, 2006. The Amendment amends the ESSRP to provide that for each of the Company's Chief Executive Officer and Corporate Secretary, the "Normal Retirement Benefit" (as defined in the ESSRP) will be determined based on "Final Average Earnings" rather than "Final Annual Salary" (defined as the base Salary (as defined in the ESSRP) and annual bonus paid to the participant during the 12 months prior to termination or death). The ESSRP defines "Final Average Earnings" as the average of the participant's total cash payments (Salary (as defined in the ESSRP) and annual incentive bonus) paid during the highest consecutive 42 months in the 10 years prior to the date as of which the Final Average Earnings are determined.

Components of net periodic pension benefit cost:

(in thousands)	2007	2006	2005
Service Cost—Benefit Earned During the Period	$ 626	$ 426	$ 406
Interest Cost on Projected Benefit Obligation	1,451	1,303	1,267
Amortization of Prior-Service Cost	67	71	71
Amortization of Net Actuarial Loss	540	473	498
Net Periodic Pension Cost	$ 2,684	$ 2,273	$ 2,242

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2007	2006
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 435	$ 496
Unrecognized Actuarial Loss	4,841	5,796
Total Regulatory Assets	5,276	6,292
Projected Benefit Obligation Liability – Net Amount Recognized	(25,158)	(24,783)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	266	271
Unrecognized Actuarial Loss	2,954	3,162
Total Accumulated Other Comprehensive Loss	3,220	3,433
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (16,662)	$ (15,058)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2007 and a statement of the funded status as of December 31 of both years:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Employer Contributions	1,079	1,124
Benefit Payments	(1,079)	(1,124)
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 24,783	$ 23,271
Service Cost	626	426
Interest Cost	1,451	1,303
Benefit Payments	(1,079)	(1,124)
Plan Amendments	—	(53)
Actuarial (Gain) Loss	(623)	960
Projected Benefit Obligation at December 31	$ 25,158	$ 24,783
Reconciliation of Funded Status:		
Funded Status at December 31	$ (25,158)	$ (24,783)
Unrecognized Net Actuarial Loss	7,795	8,958
Unrecognized Prior Service Cost	701	767
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (16,662)	$ (15,058)

Weighted-average assumptions used to determine benefit obligations at December 31:

	2007	2006
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	4.70%	4.71%

Weighted-average assumptions used to determine net periodic pension cost for the year ended December 31:

	2007	2006
Discount Rate	6.00%	5.75%
Rate of Increase in Future Compensation Level	4.71%	4.69%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 42
Amortization of Unrecognized Actuarial Loss	298
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	25
Amortization of Unrecognized Actuarial Loss	182
Total Estimated Amortization	$ 547

Cash flows—The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

(in thousands)	2008	2009	2010	2011	2012	Years 2013-2017
	$1,109	$1,114	$1,113	$1,206	$1,258	$6,755

Other Postretirement Benefits

The Company provides a portion of health insurance and life insurance benefits for retired electric utility and corporate employees. Substantially all of the Company's electric utility and corporate employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. On adoption of SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, in January 1993, the Company elected to recognize its transition obligation related to postretirement benefits earned of approximately $14,964,000 over a period of 20 years. There are no plan assets.

Components of net periodic postretirement benefit cost:

(in thousands)	2007	2006	2005
Service Cost—Benefit Earned During the Period	$ 1,098	$ 1,319	$ 1,307
Interest Cost on Projected Benefit Obligation	2,565	2,556	2,480
Amortization of Transition Obligation	748	748	748
Amortization of Prior-Service Cost	(206)	(305)	(305)
Amortization of Net Actuarial Loss	177	556	742
Expense Decrease Due to Medicare Part D Subsidy	(1,233)	(1,543)	(1,251)
Net Periodic Postretirement Benefit Cost	$ 3,149	$ 3,331	$ 3,721

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2007	2006
Regulatory Asset:		
Unrecognized Transition Obligation	$ 3,658	$ 4,414
Unrecognized Prior Service Cost	1,781	1,588
Unrecognized Net Actuarial Gain	(4,915)	(2,077)
Net Regulatory Asset	524	3,925
Projected Benefit Obligation Liability – Net Amount Recognized	(30,488)	(32,254)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	83	75
Unrecognized Prior Service Cost	40	27
Unrecognized Net Actuarial Gain	(111)	(35)
Accumulated Other Comprehensive Loss	12	67
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (29,952)	$ (28,262)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2007:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Company Contributions	1,459	2,051
Benefit Payments (Net of Medicare Part D Subsidy)	(3,127)	(3,625)
Participant Premium Payments	1,668	1,574
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 32,254	$ 36,757
Service Cost (Net of Medicare Part D Subsidy)	890	1,110
Interest Cost (Net of Medicare Part D Subsidy)	1,776	1,779
Benefit Payments (Net of Medicare Part D Subsidy)	(3,127)	(3,625)
Participant Premium Payments	1,668	1,574
Actuarial Gain	(2,973)	(5,341)
Projected Benefit Obligation at December 31	$ 30,488	$ 32,254
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$ (28,262)	$ (26,982)
Expense	(3,149)	(3,331)
Net Company Contribution	1,459	2,051
Accrued Postretirement Cost at December 31	$ (29,952)	$ (28,262)

Weighted-average assumptions used to determine benefit obligations at December 31:

	2007	2006
Discount Rate	6.25%	6.00%

Weighted-average assumptions used to determine net periodic postretirement benefit cost for the year ended December 31:

	2007	2006
Discount Rate	6.00%	5.75%

Assumed healthcare cost-trend rates as of December 31:

	2007	2006
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	8.00%	9.00%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	9.00%	10.00%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2012	2012

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2007 would have the following effects:

(in thousands)	1 point increase	1 point decrease
Effect on the Postretirement Benefit Obligation	$2,804	$(2,423)
Effect on Total of Service and Interest Cost	$ 358	$ (293)
Effect on Expense	$ 418	$ (544)

Measurement dates:	2007	2006
Net Periodic Postretirement Benefit Cost	January 1, 2007	January 1, 2006
End of Year Benefit Obligations	January 1, 2007 projected to December 31, 2007	January 1, 2006 projected to December 31, 2006

The estimated net amounts of unrecognized transition obligation and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 732
Amortization of Unrecognized Prior Service Cost	205
Amortization of Unrecognized Actuarial Gain	(200)
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	16
Amortization of Unrecognized Prior Service Cost	5
Amortization of Unrecognized Actuarial Gain	(4)
Total Estimated Amortization	$ 754

Cash flows—The Company expects to contribute $2.2 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2008. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $386,000 in 2008. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2008	2009	2010	2011	2012	Years 2013-2017
	$2,213	$2,266	$2,310	$2,294	$2,403	$13,263

Leveraged Employee Stock Ownership Plan

The Company has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $733,000 for 2007, $738,000 for 2006 and $830,000 for 2005.

13. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash and Short-Term Investments—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Other Investments—The carrying amount approximates fair value. A portion of other investments is in financial instruments that have variable interest rates that reflect fair value.

Long-Term Debt—The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. About $10.4 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

	December 31, 2007		December 31, 2006	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 39,824	$ 39,824	$ 6,791	$ 6,791
Other Investments	10,057	10,057	8,955	8,955
Long-Term Debt	(342,694)	(354,242)	(255,436)	(265,547)

14. Property, Plant and Equipment

(in thousands)	December 31, 2007	December 31, 2006
Electric Plant		
Production	$ 439,541	$ 360,304
Transmission	191,949	189,683
Distribution	322,107	307,825
General	75,320	72,877
Electric Plant	1,028,917	930,689
Less Accumulated Depreciation and Amortization	401,006	388,254
Electric Plant Net of Accumulated Depreciation	627,911	542,435
Construction Work in Progress	33,772	18,503
Net Electric Plant	$ 661,683	$ 560,938
Nonelectric Operations Plant		
Equipment	$ 181,743	$ 168,917
Buildings and Leasehold Improvements	62,563	58,733
Land	13,284	11,619
Nonelectric Operations Plant	257,590	239,269
Less Accumulated Depreciation and Amortization	105,738	91,303
Nonelectric Plant Net of Accumulated Depreciation	151,852	147,966
Construction Work in Progress	40,489	9,705
Net Nonelectric Operations Plant	$ 192,341	$ 157,671
Net Plant	$ 854,024	$ 718,609

The estimated service lives for rate-regulated properties is 5 to 65 years. For nonelectric property the estimated useful lives are from 3 to 40 years.

	Service Life Range	
(years)	Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	65
Nonelectric Fixed Assets:		
Equipment	3	12
Buildings and Leasehold Improvements	7	40

15. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2007, 2006 and 2005) to net income before total income tax expense for the following reasons:

(in thousands)	2007	2006	2005
Tax Computed at Federal Statutory Rate	$ 28,675	$ 27,232	$ 28,325
Increases (Decreases) in Tax from:			
State Income Taxes Net of Federal Income Tax Benefit	2,913	2,261	1,906
Investment Tax Credit Amortization	(1,137)	(1,146)	(1,151)
Differences Reversing in Excess of Federal Rates	929	1,271	(15)
Dividend Received/Paid Deduction	(714)	(718)	(703)
Affordable Housing Tax Credits	(285)	(839)	(1,324)
Section 199 Domestic Production Activities Deduction	(1,159)	(524)	(451)
Permanent and Other Differences	(1,254)	(431)	1,420
Total Income Tax Expense	$ 27,968	$ 27,106	$ 28,007
Income Tax Expense—Discontinued Operations	$ —	$ 252	$ 5,570
Overall Effective Federal and State Income Tax Rate	34.1%	34.9%	34.9%
Income Tax Expense Includes the Following:			
Current Federal Income Taxes	$ 23,207	$ 26,276	$ 32,795
Current State Income Taxes	2,339	4,232	5,265
Deferred Federal Income Taxes	2,832	(937)	(7,112)
Deferred State Income Taxes	2,116	(189)	(899)
Affordable Housing Tax Credits	(285)	(839)	(1,324)
Investment Tax Credit Amortization	(1,137)	(1,146)	(1,151)
Foreign Income Taxes	(1,104)	(291)	433
Total	$ 27,968	$ 27,106	$ 28,007

The Company’s deferred tax assets and liabilities were composed of the following on December 31, 2007 and 2006:

(in thousands)	2007	2006
Deferred Tax Assets		
Benefit Liabilities	$ 30,789	$ 29,418
Cost of Removal	22,537	22,813
Related to North Dakota Wind Tax Credits	12,999	—
SFAS No. 158 Liabilities	10,504	14,694
Differences Related to Property	8,703	7,923
Amortization of Tax Credits	4,505	5,231
Vacation Accrual	2,926	2,751
Unearned Revenue	1,733	2,013
Other	4,063	3,382
Total Deferred Tax Assets	$ 98,759	$ 88,225
Deferred Tax Liabilities		
Differences Related to Property	$(166,445)	$(160,635)
SFAS No. 158 Regulatory Asset	(10,504)	(14,694)
Transfer to Regulatory Asset	(8,732)	(11,712)
Related to North Dakota Wind Tax Credits	(4,340)	—
Excess Tax over Book Pension	(2,953)	(3,153)
Other	(4,398)	(2,702)
Total Deferred Tax Liabilities	$(197,372)	$(192,896)
Deferred Income Taxes	$ (98,613)	$(104,671)

On January 1, 2007 the Company adopted the provisions of FIN No. 48. The cumulative effect of adoption of FIN No. 48, which is reported as an adjustment to the beginning balance of retained earnings, was $118,000. As of the date of adoption, the total amount of unrecognized tax benefits for uncertain tax positions was $1,874,000. The amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate was $575,000 as of January 1, 2007.

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	Total
Balance at January 1, 2007	$ 1,874
Increases Related to Current Year Tax Positions	198
Expiration of the Statute of Limitations for the Assessment of Taxes	(1,566)
Balance at December 31, 2007	$ 506

The balance of unrecognized tax benefits as of December 31, 2007 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2007 is not expected to change significantly within the next 12 months. The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2007 the Company is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2004. As of December 31, 2007 the Company's earliest open tax year in which an audit can be initiated by state taxing authorities in the Company's major operating jurisdictions is 2003 for Minnesota and 2004 for North Dakota. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. Amounts accrued for interest and penalties on tax uncertainties as of December 31, 2007 were not material.

16. Discontinued Operations

In 2006, the Company sold the natural gas marketing operations of OTESCO, the Company's energy services subsidiary. Discontinued Operations includes the operating results of OTESCO's natural gas marketing operations for 2006 and 2005. Discontinued Operations also includes an after-tax gain on the sale of OTESCO's natural gas marketing operations of $0.3 million in 2006.

In 2005, the Company sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Discontinued operations includes the operating results of MIS, SGS and CLC for 2005. Discontinued Operations also includes an after-tax gain on the sale of MIS of $11.9 million, an after-tax loss on the sale of SGS of $1.7 million and an after-tax loss on the sale of CLC of $0.2 million in 2005. OTESCO's natural gas marketing operations, MIS, SGS and CLC meet requirements to be reported as discontinued operations in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

The results of discontinued operations for the years ended December 31, 2006 and 2005 are summarized as follows:

2006	
(in thousands)	OTESCO Gas
Operating Revenues	$28,234
Income Before Income Taxes	54
Gain on Disposition — Pretax	560
Income Tax Expense	252

2005					
(in thousands)	OTESCO Gas	MIS	SGS	CLC	Total
Operating Revenues	$64,539	$ 3,773	$ 6,564	$6,112	$80,988
Income (Loss) Before Income Taxes	(84)	2,167	(1,740)	(956)	(613)
Goodwill Impairment Loss	(1,003)	—	—	—	(1,003)
Gain (Loss) on Disposition — Pretax	—	19,025	(2,919)	(271)	15,835
Income Tax (Benefit) Expense	(40)	7,975	(1,863)	(502)	5,570

The remaining assets and liabilities of Discontinued Operations as of December 31, 2006 were SGS's deferred tax assets of $289,000 and warranty reserves of $197,000 at estimated fair market values that were settled or disposed in 2007.

17. Asset Retirement Obligations (AROs)

The Company's AROs are related to coal-fired generation plants and 27 wind turbines erected near Langdon, North Dakota and include site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

During 2007, the Company recorded new obligations related to the removal of 27 wind turbines erected near Langdon, North Dakota and restoration of the tower sites but did not make any revisions to previously recorded obligations.

During 2006, the Company did not record any new obligation or make any revisions to previously recorded obligations. The Company settled a legal obligation for removal of asbestos at unit one of its Hoot Lake generating plant.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2007 and 2006 are presented in the following table:

(in thousands)	2007	2006
Asset Retirement Obligations		
Beginning Balance	$ 1,335	$ 1,524
New Obligations Recognized	1,024	—
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Accrued Accretion	88	85
Settlements	—	(274)
Ending Balance	$ 2,447	$ 1,335
Asset Retirement Costs Capitalized		
Beginning Balance	$ 285	$ 349
New Obligations Recognized	1,024	—
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Settlements	—	(64)
Ending Balance	$ 1,309	$ 285
Accumulated Depreciation — Asset Retirement Costs Capitalized		
Beginning Balance	$ 178	$ 234
New Obligations Recognized	—	—
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Accrued Depreciation	7	8
Settlements	—	(64)
Ending Balance	$ 185	$ 178
Settlements		
Original Capitalized Asset Retirement Cost — Retired	$ —	$ 64
Accumulated Depreciation	—	(64)
Asset Retirement Obligation	$ —	$ 274
Settlement Cost	—	(222)
Gain on Settlement – Deferred Under Regulatory Accounting	$ —	$ 52

18. Quarterly Information (not audited)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings per common share may not equal total earnings per common share.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	2007	2006	2007	2006	2007	2006	2007	2006
Operating Revenues *(a)*	$301,121	$257,807	$305,844	$279,904	$302,235	$280,542	$329,687	$286,701
Operating Income *(a)*	20,774	27,374	30,271	22,136	25,547	24,170	24,182	24,117
Net Income:								
Continuing Operations	10,408	14,855	16,103	11,137	13,332	13,476	14,118	11,282
Discontinued Operations	—	105	—	257	—	—	—	—
	10,408	14,960	16,103	11,394	13,332	13,476	14,118	11,282
Earnings Available for Common Shares:								
Continuing Operations	10,224	14,671	15,919	10,953	13,148	13,293	13,934	11,097
Discontinued Operations	—	105	—	257	—	—	—	—
	10,224	14,776	15,919	11,210	13,148	13,293	13,934	11,097
Basic Earnings Per Share:								
Continuing Operations	$ .35	$ .50	$ .54	$ .37	$ .44	$ .45	$ .47	$ .38
Discontinued Operations	—	—	—	.01	—	—	—	—
	.35	.50	.54	.38	.44	.45	.47	.38
Diluted Earnings Per Share:								
Continuing Operations	$ .34	$ .50	$ .53	$ .37	$ .44	$ .45	$ .46	$ .37
Discontinued Operations	—	—	—	.01	—	—	—	—
	.34	.50	.53	.38	.44	.45	.46	.37
Dividends Paid Per Common Share	.2925	.2875	.2925	.2875	.2925	.2875	.2925	.2875
Price Range:								
High	$ 35.00	$ 31.34	$ 37.06	$ 30.09	$ 39.39	$ 30.80	$ 37.88	$ 31.92
Low	31.06	27.32	30.22	25.78	28.96	26.50	32.82	28.60
Average Number of Common Shares Outstanding—Basic	29,503	29,326	29,686	29,393	29,746	29,413	29,790	29,445
Average Number of Common Shares Outstanding—Diluted	29,757	29,676	29,941	29,766	29,996	29,806	30,090	29,731

(a) From continuing operations.

Stock Listing

Otter Tail Corporation common stock trades on The NASDAQ Global Select Market.

(Back To Top)

Section 4: EX-21.A (SUBSIDIARIES)

Exhibit 21-A

OTTER TAIL CORPORATION

Subsidiaries of the Registrant
February 28, 2008

Company	State of Organization
Otter Tail Energy Services Company, Inc.	Minnesota
Overland Mechanical Services, Inc.	Minnesota
Green Hills Energy, LLC	Minnesota
Sheridan Ridge I, LLC	Minnesota
Sheridan Ridge II, LLC	Minnesota
Otter Tail Assurance Limited	Cayman Islands
Varistar Corporation	Minnesota
Northern Pipe Products, Inc.	North Dakota
Vinyltech Corporation	Arizona
T.O. Plastics, Inc.	Minnesota
St. George Steel Fabrication, Inc.*	Utah
DMI Industries, Inc.	North Dakota
DMI Canada, Inc.	Ontario, Canada
BTD Manufacturing, Inc.	Minnesota
ShoreMaster, Inc.	Minnesota
Galva Foam Marine Industries, Inc.	Missouri
Shoreline Industries, Inc.	Minnesota
Aviva Sports, Inc.	Minnesota
ShoreMaster Costa Rica, Limitada	Costa Rica
DMS Health Technologies, Inc.	North Dakota
DMS Imaging, Inc.	North Dakota
DMS Imaging Partners, LLC*	Delaware
DMS Imaging Partners II, LLC*	Delaware
DMS Leasing Corporation*	North Dakota
Midwest Construction Services, Inc.	Minnesota
Aerial Contractors, Inc.	North Dakota
Moorhead Electric, Inc.	Minnesota
Lynk3 Technologies, Inc	Minnesota
AC Equipment, Inc.	Minnesota
Ventus Energy Systems, Inc.	Minnesota
Foley Company	Missouri
Chassis Liner Corporation*	Minnesota
E. W. Wylie Corporation	North Dakota
Idaho Pacific Holdings, Inc.	Delaware
Idaho-Pacific Corporation	Idaho
Idaho-Pacific Colorado Corporation	Delaware
AWI Acquisition Company Limited	Prince Edward Island, Canada
AgraWest Investments Limited	Prince Edward Island, Canada

* Inactive

(Back To Top)

Section 5: EX-23.A (CONSENT OF DELOITTE & TOUCHE LLP)

EXHIBIT 23-A

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-116206, 333-90952 and 333-11145 on Form S-3 and 333-25261, 333-73041, 333-136841 and 333-73075 on Form S-8 of our report dated February 20, 2008 relating to the consolidated financial statements of Otter Tail Corporation and its subsidiaries (the "Company") and management's report on the effectiveness of internal control over financial reporting (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the December 31, 2006, adoption of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans)* appearing in the 2007 Annual Report to Shareholders of the Company and incorporated by reference in this Annual Report on Form 10-K of the Company for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 28, 2008

(Back To Top)

Section 6: EX-24.A (POWERS OF ATTORNEY)

Exhibit 24-A

POWER OF ATTORNEY

I, KEVIN G. MOUG, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Chief Financial Officer and Treasurer of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ Kevin G. Moug
Kevin G. Moug

In Presence of:

/s/ Lauris N. Molbert

/s/ John Erickson

POWER OF ATTORNEY

I, John MacFarlane, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ John MacFarlane
John MacFarlane

In Presence of:

/s/ Edward McIntyre

/s/ Arvid Liebe

POWER OF ATTORNEY

I, Karen Bohn, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ Karen Bohn
Karen Bohn

In Presence of:

/s/ Nathan Partain

/s/ Lori Talafous

POWER OF ATTORNEY

I, Dennis Emmen, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ Dennis Emmen
Dennis Emmen

In Presence of:

/s/ Joyce Nelson Schuette

/s/ Lori Talafous

POWER OF ATTORNEY

I, Arvid Liebe, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ Arvid Liebe
Arvid Liebe

In Presence of:

/s/ Gary Spies

/s/ James Stake

POWER OF ATTORNEY

I, Edward J. McIntyre, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ Edward J. McIntyre
Edward J. McIntyre

In Presence of:

/s/ John MacFarlane

/s/ James B. Stake

POWER OF ATTORNEY

I, Joyce Nelson Schuette, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ Joyce Nelson Schuette
Joyce Nelson Schuette

In Presence of:

/s/ Dennis Emmen

/s/ Kevin Moug

POWER OF ATTORNEY

I, Nathan Partain, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ Nathan Partain
Nathan Partain

In Presence of:

/s/ Karen Bohn

/s/ Lori Talafous

POWER OF ATTORNEY

I, Gary Spies, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2007, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: February 6, 2008

/s/ Gary Spies
Gary Spies

In Presence of:

/s/ Arvid Liebe

/s/ James B. Stake

(Back To Top)

Section 7: EX-31.1 (CERTIFICATION OF CHIEF EXECUTIVE OFFICER)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John D. Erickson, certify that:

1. I have reviewed this Annual Report on Form 10-K of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ John D. Erickson
John D. Erickson
President and Chief Executive Officer

(Back To Top)

Section 8: EX-31.2 (CERTIFICATION OF CHIEF FINANCIAL OFFICER)

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kevin G. Moug, certify that:

1. I have reviewed this Annual Report on Form 10-K of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2008

/s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Treasurer

(Back To Top)

Section 9: EX-32.1 (SECTION 906 CERTIFICATION OF CEO)

Exhibit 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Otter Tail Corporation (the "Company") on Form 10-K for the period ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John D. Erickson, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ John D. Erickson
John D. Erickson
President and Chief Executive Officer
February 28, 2008

(Back To Top)

Section 10: EX-32.2 (SECTION 906 CERTIFICATION OF CFO)

Exhibit 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Otter Tail Corporation (the “Company”) on Form 10-K for the period ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Kevin G. Moug, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Treasurer
February 28, 2008

(Back To Top)